EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD

Ontario

ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARINGS

VOLUME: 167

DATE: Monday, October 26, 1992

BEFORE:

HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

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EA-90-01

ENVIRONMENTAL ASSESSMENT BOARD
ONTARIO HYDRO DEMAND/SUPPLY PLAN HEARING

IN THE MATTER OF the Environmental Assessment Act, R.S.O. 1980, c. 140, as amended, and Regulations thereunder;

AND IN THE MATTER OF an undertaking by Ontario Hydro consisting of a program in respect of activities associated with meeting future electricity requirements in Ontario.

Held on the 5th Floor, 2200 Yonge Street, Toronto, Ontario, Monday, the 26th day of October, 1992, commencing at 9:00 a.m.

VOLUME 167

B E F O R E :

THE HON. MR. JUSTICE E. SAUNDERS	Chairman
DR. G. CONNELL	Member
MS. G. PATTERSON	Member

S T A F F :

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L. BULLOCK	)	CANADIAN NUCLEAR ASSOCIATION
L. CHAN	)	
R. MATSUI	)	
M. ANSHAN		CAESCO

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TIME NOTATIONS

---Upon commencing at 9:00 a.m.

THE REGISTRAR: This hearing is now in order.

THE CHAIRMAN: Just a moment, Mr. Greenspoon, just a couple of housekeeping matters to attend to first.

Since we were last in session in June there have been a number of documents filed which have been given exhibit numbers. They start at 731 and go through to up to and including 778.

There are copies of the lists available and in addition to that the numbers and the filing party and the description of the document will be included in the transcript.

---EXHIBIT NOS. 731-780: See front pages.

THE CHAIRMAN: Now, Mr. Greenspoon, you were on your feet.

MR. GREENSPOON: Yes. I just had a very short submission, Mr. Chairman.

THE CHAIRMAN: On what?

MR. GREENSPOON: I filed a motion this morning for early dismissal and I thought that I should put on the record that fact because today is in fact the day that the evidence for the intervenors is scheduled to start.

I wish to make a submission with regard to that motion. I have spoken with my friend Mr. Campbell about this. And that is that the earliest date that was available to hear this motion was the 16th of November. We have set the motion down for that date. And prior to that time, subject to this panel's ruling Northwatch does intend to call evidence on Panel 1.

I spoke with my friend about the issue of calling evidence without prejudice to this motion because it is somewhat analogous to a motion for a nonsuit in civil matters. My understanding is that there is a difference in administrative matters.

So I wish to make that clear to the Board that we ask the Board to take that into account that we are making our presentation of evidence in Panel 1 without prejudice to this application.

THE CHAIRMAN: Well, that is satisfactory. I take it no one has any objection to that, what Mr. Greenspoon was saying.

Your participation in this panel will not in any way affect, one way or the other, the motion which you have brought.

MR. GREENSPOON: Thank you, sir.

THE CHAIRMAN: Mr. Campbell.

MR. B. CAMPBELL: Mr. Chairman, there is a matter that I want to be sure that the Board is aware of. I have sent correspondence to the Board over the last two months to Ms. Morrison and I think everyone is aware of it but I think perhaps I should just put it on the record at this time.

At the time of the Update Ontario Hydro put forward an illustrative approach to managing the projected surplus and the Board will recall that in Exhibit 452 it was noted specifically that Hydro would be regularly reviewing the response portfolio and the steps which should be taken from time to time, the related actions, during the normal course of the corporation's planning cycle. That has gone on.

And on September 16th I advised the Board, by way of letter to Ms. Morrison, that changes were being contemplated to the capital program.

And on October 19th, following the board of directors' meeting, I advised Ms. Morrison that certain decisions had been made by Hydro's board of directors.

In particular, I want to draw to the Board's attention that Ontario Hydro is seeking from Manitoba Hydro a mutually agreeable five-year deferral of the taking of power pursuant to the Manitoba

contract and as well Ontario Hydro's board of directors has put in place a deferral of up to ten years on the Little Jackfish and Patten Post projects.

Taken at the broad level, these changes in Ontario Hydro's view do not require any amendment to the formal statement of approvals as they now stand before the Board, but the decisions taken do relate to some of the considerations relating to these approvals and for that reason we wanted to be sure that they were brought to the Board's and the parties' attention.

The discussions with Manitoba with respect to the Manitoba contract are under way and I will advise the Board and parties of the outcome. I think, hopefully, that will be by late November but of course these kinds of discussions, being what they are, I can't absolutely guarantee that date.

In that regard, with respect to the motion that my friend Mr. Greenspoon has brought, it may be that as we get a little closer to the November 16th date, if the Manitoba Contract matter has not been resolved but looks like it would be resolved in the fairly near future or if that's my sense of it having been briefed, I may return to the Board to ask that the November 16th date be put somewhat later so that we could argue that motion on the basis of the outcome of

those discussions with Manitoba.

Subject to any questions the Board may have, I just wanted to bring those matters to the Board's attention.

THE CHAIRMAN: Just so I understand. What you are saying is that Ontario Hydro is still seeking approval for the transmission related to the Manitoba Purchase?

MR. B. CAMPBELL: Those are my current instructions, Mr. Chairman.

THE CHAIRMAN: Well then I don't quite see why, what difference it would make to the motion of the 16th, but perhaps I will leave that to that date.

MR. B. CAMPBELL: I just put a note of caution there. These kinds of discussions may take some strange twist or turn that may lead me to ask that the date be postponed and I just wanted to, from an abundance of caution, make sure that I didn't leave that to the last moment.

THE CHAIRMAN: All right. Thank you.

Any parties want to make any comments on events that have occurred subsequent to our last formal meeting? Yes, Mr. Starkman?

MR. STARKMAN: Mr. Chairman, the only thing I want to clarify at this time is - and this is

subject to, or further to, Mr. Campbell's statement - is that I take that it is still Hydro's position that they need the additional capacity that they initially requested. If you like, it is a follow-up on him saying Hydro has deferred Patten Post and Mattagami for another -- which one?

MR. GREENSPOON: Little Jackfish.

MR. STARKMAN: And Little Jackfish, sorry, for 10 years. But I take it that their position is they still need the hydraulic capacity in the same numbers that they requested it and presented their evidence during the past year. I just want to be clear that they are taking the view that they need what they --

THE CHAIRMAN: The range of what -- I forget it, 1,300 to -- 1,400 to 1,800, that range. Is that what you mean?

MR. STARKMAN: Yes, they still need that range and they still need the Manitoba transmission and so forth, that that's their position now.

THE CHAIRMAN: Well, I think he is clear about Manitoba transmission. Perhaps you could just clarify the range question.

MR. B. CAMPBELL: On the range of hydraulic, Mr. Chairman, you will recall that Exhibit

360, which I prepared following the Board's ruling, indicates that the formal approval would be for a specified range of hydraulic capacity. And the evidence of Panel 6 was that that range should be in the neighbourhood of 14 to 1,800 megawatts.

We take the position that the actual identification of the range is a matter for argument based on the evidence, and the deferral of Patten Post and Little Jackfish may have affect submissions as to the appropriate range to be plugged in, if you will, to the formal approval.

THE CHAIRMAN: I'm not entirely clear about that. As I understand it, the application right now is for a range that -- you are requesting approval for a range from 1,400 to 1,800 megawatts. Am I right about that? It is not that indefinite. It is a request for an approval for a range within that. I haven't got the papers in front of me. Is that not correct?

MR. B. CAMPBELL: I think at the bottom line that's how things stand at the moment. I would just caution that the way this matter is set out in Exhibit 452, which is based on Exhibit 360, is that the approval that is being requested is with respect to a specified range of hydraulic capacity and energy, and

Ontario Hydro's position on the evidence to date is that that range should be 14 to 1,800 megawatts.

At the moment I have no instructions to change that range but obviously that is a matter that is being given some consideration.

THE CHAIRMAN: Well, I just want to make sure that I understand. You are not changing the approvals that you are requesting at day 166 when we last had a hearing of evidence; is that correct?

MR. B. CAMPBELL: That is correct.

THE CHAIRMAN: Yes. All right.

Is that a satisfactory answer, Mr. Starkman?

MR. STARKMAN: Well, Mr. Chairman, I could say the answer is not satisfactory, but what I take away from it is that Ontario Hydro today continues to take the position that they need 14 to 1,800 megawatts of hydraulic capacity. That's what I take from that. They are not changing that and that continues to be their view.

THE CHAIRMAN: I think the inferences you can draw may be very many and varied but the simple situation is the request for approvals before this Board have not changed. I think that's the situation.

MR. STARKMAN: Yes, Mr. Chairman, but --

THE CHAIRMAN: Which is a requirement and rationale for 14 to 1,800 megawatts of hydraulic capacity.

MR. STARKMAN: And I take from that that they continue to assert that they need 14 to 1,800 megawatts of hydraulic capacity. And if that's not so, I would like that clarified.

[9:10 a.m.]

MR. B. CAMPBELL: I can deal with that directly.

We do take the position, to use the word directly out of Section 5(3) of the Act, that there is a rationale for that.

THE CHAIRMAN: Anyone else? Before we start on the IPPSO intervenor evidence?

Mr. Hamer?

MR. HAMER: Mr. Chairman, I'm not rising to deal with what has just been raised by Mr. Starkman and Mr. Campbell, except peripherally. I learned last week that a speech which had been given by the outgoing chairman of Ontario Hydro, Mr. Eliesen, had been tendered as an exhibit in the hearing and given an exhibit number. And I wanted, while we are on the record, to express our concern about that kind of material going in, in that manner.

If there should be any intention on the part of any party to suggest to the Board at the end of the case that any reliance whatsoever should be placed upon pieces of paper which come in from the world out there not spoken to by the author of the piece of paper, or by any witness authorized by Hydro to adopt the contents of a speech like that, it will be our position that Ontario Hydro's case is closed, at least in chief, and although this tribunal applies broader rules of admissibility than a court would in civil or criminal litigation, we are not at the point where we should all start to file the daily newspaper whenever we see something in the paper that we think is favourable to our client's position.

It is our submission that the attaching of a number to a piece of paper like Mr. Eliesen's transcript is nothing more than that; it has the same evidentiary value as some of the newspaper clippings that have been filed as parts of larger bundles of documents.

It appears to us that when a document is tendered and given an exhibit number, it's obviously intended to influence --

THE CHAIRMAN: By the way, what exhibit number was it given?

MR. HAMER: I'm sorry, I didn't get the number.

MS. MORRISON: 780.

THE CHAIRMAN: There are two more, excuse me, housekeeping matters. My list stopped at 778 and apparently since that time there have been two additional exhibits, No. 779 and 780. 780 is appears to be the one that you are referring to, it was filed by IPPSO and it is a document entitled "Beyond the Metre", Mark Eliesen, Chair, Ontario Hydro, October 21, 1992. That is the document you are referring to.

MR. HAMER: Yes.

THE CHAIRMAN: All right.

MR. HAMER: As I was saying, in tendering a document like that --

THE CHAIRMAN: Excuse me, just so I understand, this was a speech that Mr. Eliesen made last week; is that correct?

MR. HAMER: I understand so.

In tendering a document like that, it seems to us that the objective is to influence your analysis and conclusions in this case to some extent, and we don't want, by standing by, to be taken as in any way as conceding that there is any value whatsoever to a document placed in the reading room, as it were,

in that manner.

It is said sometimes, well, this can all go to weight, and that we will admit it but it will go to weight.

I say that if a document has zero weight, it ought not go into the record in any way that can be relied upon.

Until Mr. Eliesen comes and says the things here that he may have said elsewhere or expresses the opinions here that he may have expressed elsewhere, or until someone authorized by Ontario Hydro adopts similar opinions or analysis, that document has no weight whatsoever, in our submission. We want to make our position clear now rather than at the end of the case.

THE CHAIRMAN: And your position is that it has no weight and should not be an exhibit; is that what you are saying?

MR. HAMER: Well, it's difficult to say that it shouldn't be given a number, but it is important that the giving of a number not be given any significance by anybody.

THE CHAIRMAN: All right. Before I ask Mr. Shepherd, who is the filer of the document, Mr. Campbell, what do you say about this?

MR. M. CAMPBELL: Well, Mr. Chairman, I think we raised some concerns about this kind of thing very early on in the hearing and I thought you had made it perfectly clear that numbers were being given out, in effect, for identification of document purposes, but that nothing in any of those documents would be given any weight by the Board until such time as they were spoken to directly by witnesses. I thought that understanding was quite clear and it is certainly the basis on which we have been proceeding and which I believe attaches to Exhibit 780.

THE CHAIRMAN: Mr. Starkman was up first, Mr. Watson, I ask him and then you.

MR. STARKMAN: Mr. Chairman, if everybody is trying to make their view clear, let me try and make our view clear, we understand the ruling of the Panel or the thoughts of the Panel with respect to the filing of evidence, and that a matter is not addressed directly it will be given little weight or would be given -- let's put it another way, matters that are addressed extensively will be given more weight.

But I think you have to keep in mind that this is a speech by the chairman of Ontario Hydro. It's not any piece of paper, this is not any newspaper clipping. This is a speech by the chairman of Ontario

Hydro, that is the proponent, the chair of the board of directors of the proponent in this undertaking. And I guess it's our view, put very simply, that those speeches, those statements reflect the views of Ontario Hydro.

THE CHAIRMAN: Just so I am clear, I haven't seen the document, is it actually a transcript of the speech?

MR. STARKMAN: I think it is one of those type of speeches where it says, this is the text although the actual delivery may vary somewhat from the --

MR. B. CAMPBELL: What it says, Mr. Chairman, is notes for remarks.

MR. STARKMAN: Just to finish the thought, it is our view -- I will put it another way.

When the Hydro witnesses were testifying there was this question as to whether what they were saying were their personal views or the views of Ontario, and I thought that the general understanding was that they were Ontario Hydro's -- that the witnesses were expressing Ontario Hydro's position unless they said something for indicate to the contrary. We say the same about Mr. Eliesen's speech. He is the chairman of Ontario Hydro. His views, in our

submission, reflect the views of Ontario Hydro unless they are disowned by the Corporation or unless the Corporation comes out and makes it clear these are not the views of the Corporation. There is no other reasonable way to proceed to understand what someone like the chair of Ontario Hydro says in public forums, especially following board of directors' meetings, and so forth, where they are considering the future plans.

I guess if it really comes down to a matter, we can have Mr. Eliesen here to testify about his speech, so this matter can be easily overcome. But I think the more reasonable way is to say that documents that are marked as exhibits, the importance that's attached to them varies depending on their source, and the matter must be viewed in context by the Board.

So I think you shouldn't make a definitive ruling on this. This matter should be addressed in the normal course of argument and evidence. Thank you.

THE CHAIRMAN: Mr. Watson?

MR. R. WATSON: Mr. Chairman, to quote Mr. Campbell from our scoping motion, Mr. Campbell got it exactly right when he made his submissions to you. When documents are put here and given a number, that's

simply for identification.

The way the exhibits become evidence is if a witness adopts the document or if parts of a document are put to the witnesses and they adopt that part, or they give their evidence with respect to that part of the document that's put to them. And I would suggest a quick review of the transcript would reveal that you have already dealt with this and made exactly that ruling.

THE CHAIRMAN: Anyone else before Mr. Shepherd?

MR. SHEPHERD: Mr. Chairman, I think we are all being too much like lawyers here and trying to exclude the real world from this hearing.

It seems to me rather self-evident that notwithstanding that I agree with Mr. Hamer that Ontario Hydro has ended its case, closed its case, the real world is still happening out there. Ontario Hydro is still making decisions, they are still making a announcements, stating their positions, and various other things like that. We can't just ignore all that. Nor can we expect that every time something happens out there, that we have to trot out some new Ontario Hydro witnesses to make sure that it clearly follows all the rules of evidence.

Undoubtedly, a document which is a speech by the chair of Ontario Hydro has a different weight than an expert's report that is subjected to cross-examination and the whole song and dance. There is no question about that.

But, for example, we expect that we will be filing some sworn testimony of Hydro witnesses from the Ontario Energy Board as exhibits. We don't expect to have to bring those people in and do it all over again. Those are things that they have said under oath and they have been cross-examined on. It still has less weight than something that is said under oath and cross-examined here and perhaps has more weight than Mr. Eliesen's speech, but this is a matter for practical reality. This is not a matter for applying very strict precise rules.

[9:20 a.m.]

Just to give you an example. Mr. Hamer's argument would say that the material filed in the last month by Ontario Hydro, by Ontario Hydro now, with respect to the changes in their decision-making including Mr. Campbell's announcement this morning --

THE CHAIRMAN: None of those, I don't think just to make it absolutely clear and I could be wrong, I don't think either the September 16th

communication or the October 19th communication are exhibits, have been marked as such.

MR. SHEPHERD: But, Mr. Chairman, the point is not whether they are exhibits; the point is whether you are allowed to consider them in your decision. That's what we are talking about here. Whether they are evidence you can consider.

And it would be completely absurd for this Board not to be able to consider major decisions the Hydro Board is making right now. That's just silly.

The same thing is true of any other information that is presented to you that legitimately has an effect on your decision. Yes, you have to look at the weight of it and yes, you have to give more weight to things that are subjected to the rigours of cross-examination and the like, but you cannot ignore the real world simply because it doesn't comply with the rules of the Supreme Court of Justice. Those are my submissions.

THE CHAIRMAN: Thank you.

MR. HAMER: I'm not sure if there is anyone else?

THE CHAIRMAN: If there is anyone else they had better stand.

MR. HAMER: Mr. Chairman, I had thought you had made it clear as to the value of exhibit numbers earlier and it was only at an off-the-record meeting of the parties on Friday that I recognized that there may be some disagreement as to the value being placed on exhibit numbers by various people.

Certainly if someone wants to file transcripts of witnesses who testified at another hearing, I would have the same objection. I wasn't at the other hearing to cross-examine any of those witnesses. Obviously no one cross-examined Mr. Eliesen on his speech and Hydro has presented a case with numerous witnesses, extensive support and documentation. We have all cross-examined on that.

Now it appears that some parties want to put in piece of paper to say that Hydro's case is now something different and not to have the courage to call the authors of those documents to be subjected to cross-examination. And that's just wrong. If they want that information in, call the witness.

THE CHAIRMAN: An issue has been raised about Exhibit 780 which was filed subsequent to the closing of the proponent's case. Exhibit 780 is a document entitled "Beyond the Meter". It is described as notes and remarks by Mr. Eliesen, the chief

executive officer of the proponent, made on October 21, 1992. The issue is the extent to which this document, which is filed by one of the intervenors, should be taken into account in this hearing.

The practice which was adopted when the proponent was putting in its case was that any document could be used by a cross-examiner for the purpose of eliciting Hydro's position from the Hydro witnesses who were testifying under oath. So a great number of various documents, newspaper articles, brochures, learned papers, and documents of different types were brought forward and given exhibit numbers for identification purposes. It was made clear that these documents were not evidence.

We now are in a new mode, a new situation. Hydro's case is completed and we are now into the intervenor stage. The question as to what weight, if any, that should be given to Exhibit 780 is quite pertinent.

Of course, as Mr. Shepherd points out, one has to be aware of the real world and we have been experiencing the dynamics of this situation as the hearing goes on. We know that there have been many changes and that there will be many more changes before the hearing is completed.

This is an administrative tribunal and as most of you are aware, the rules of admissibility are much more flexible than they are in a court of law. On the other hand, there is a real danger that if too liberal a position is taken on admissibility of documents, the tribunal would become embedded in a morass of material which it would be unable to sort out.

We think that we should take the position that the document that has been put forward as Exhibit 780 is of no evidentiary value whatsoever in this hearing and will not be taken into account in our decision. We intend to adopt that view with similar material.

The statement that Hydro's case is closed would be perhaps true if this were a trial but in the realities of the situation that cannot be so. We know that there are going to be and there have been developments which are going to have to be addressed at some point. I am sure we are going to have to hear further testimony from the proponent. How this is going to be worked out is going to be very, very difficult but we are going to have to do it. The parties should recognize that there is a distinction between the changes that impinge on their cases and the

changes that do not.

So we would expect, and I'm sure will receive, the same kind of co-operation that we have had to date from the parties. It's very, very difficult to handle these kind of problems in a hearing of this nature and of this magnitude.

Now, before we --

MR. SHEPHERD: Mr. Chairman, can I ask two points of clarification.

THE CHAIRMAN: Yes, certainly.

MR. SHEPHERD: The first is you made a comment that this is -- or you have decided that this piece of material is not evidence. Does that apply to all things that are not testified to by witnesses or are you saying that you are going to go that far and we will deal with the other ones later like OEB transcripts, for example?

THE CHAIRMAN: I haven't picked and chosen amongst the exhibits. You would have to go through -- each document has its own characteristics. It is very hard to generalize about that.

For instance, let us take as an example right out of the air document 521 which is your document and is Mr. Kinosian's paper about the San Onofre. Now that was put in and given No. 521 in order

for you to examine the Hydro witnesses. At that point it had no other significance in this hearing. It assumes a new significance today when the witness comes in and testifies about it.

Now there may be documents that fall in between that. There may be documents that you have put in on which you do not intend to call the author of the document but which you do want to make part of your case. I would suggest, and I am just thinking about it for the first time, that if there are documents of that character they should be brought to the attention of the hearing and they could be dealt with on that basis.

I think that's the best way to handle that.

MR. SHEPHERD: I understand that. The second thing, my second question is and following along your example of Mr. Kinosian, is it still acceptable for parties to file documents with the intention then of calling perhaps an adverse witness like Mr. Eliesen to in effect perfect those documents as evidence?

So, for example, we have in Exhibit 780, which is Mr. Eliesen's speech, if we feel it is important enough to make sure that you deal with it, we could bring Mr. Eliesen later; correct?

THE CHAIRMAN: There is no property in a

witness. You can call a Hydro witness as part of your case. There is no doubt about that.

MR. SHEPHERD: Thank you.

THE CHAIRMAN: Now then are we ready to start, Mr. Shepherd.

MR. SHEPHERD: Mr. Chairman, in the interests of efficiency and if it is acceptable to the Board, I will lead my two witnesses as a single panel dealing with two subjects. Mr. Marcus is dealing with reliability and then both witnesses are dealing with the rehabilitation and fixing up of the existing system.

ROBERT KINOSIAN,
WILLIAM B. MARCUS; Sworn.

MR. SHEPHERD: Mr. Chairman, as the first person leading evidence, I guess I have to break the ground. The practice, I think, has been for the description of qualifications to be done by counsel unless you would prefer otherwise. I don't intend to go through people's CVs but just to introduce the witnesses if that's acceptable.

THE CHAIRMAN: And then if there is any parties that wish to cross-examine the witness on those qualifications before they start, they can do that at that point.

MR. SHEPHERD: Yes, of course.

So, Mr. Chairman, I would like to introduce to you Robert Kinosian who is a mechanical engineer and for the last eight years has been a resource analyst, an energy economist, I guess, in the energy resources branch of the division of ratepayer advocates of the California Public Utilities Commission.

And the second witness I would introduce to you is Mr. William Marcus. Mr. Marcus, of course, you have seen before a number of times here. He is the principal economist of JBS Energy Inc. and is a well-known energy economist. I don't think I have to go into any more detail on these people; their CVs are before you.

THE CHAIRMAN: Are there any parties who wish to examine either witness now? That doesn't preclude of course talking about their qualifications when you come to do your cross-examination. But if there is anyone that now has any concerns about these witnesses and their qualifications, if they have got questions they want to ask the witnesses they can do so.

All right, Mr. Shepherd, you can proceed.

DIRECT EXAMINATION BY MR. SHEPHERD:

Q. Then what I would like to do is start with the reliability evidence of Mr. Marcus and then do the existing system evidence of both witnesses.

So, Mr. Marcus, let me turn to you. And perhaps you could take out your Exhibit 739 on reliability.

MR. MARCUS: A. Yes.

Q. Mr. Chairman, this is the document entitled "Comparing the Reliability and Resource Reserve Margins of Nuclear Generation to Non-Utility Generation on the Ontario Hydro System".

Mr. Marcus, could you distill that material into the basic points you are making here?

A. I think that there are -- am I on here or not?

---Off the record discussion.

MR. MARCUS: I think this works. Could you ask your question again, Mr. Shepherd, just so that it looks a little less disjointed on the transcript.

MR. SHEPHERD: Q. Could you distill your material in Exhibit 739 into the basic points you are making there.

MR. MARCUS: A. There are three basic rather simple points that Exhibit 739 is designed to

prove. The first is that what the system mix is has significant effects on what Ontario Hydro's overall reserve margin should be. Different resources have different contributions to the system reserve margin.

The second point that follows from that is that all else being equal, smaller units will tend to lower the reserve margin by reducing the probability of extreme events.

And the third point that then follows from both of these other two points is whatever the appropriate reserve margin is today, it should be expected to decline somewhat over time as more non-utility generators or NUGs are added to the Ontario Hydro system because these NUG units will in large part be smaller than units that would otherwise be added to the system and that are on the existing system.

[9:35 a.m.]

Q. Mr. Marcus, is system mix the only variable driving the reserve margin?

A. No, it isn't. It's probably one of the most important if not the most important variables, but there are other variables with effects on the reserve margin, including the load shape.

If a utility's load shape is somewhat more peaked, it will a lower reserve need than if its

load shape is flatter; the amount of external support that the Ontario Hydro gets from interconnections is a subject that I think Mr. Lanzalotta will be bringing to you later has an effect; load uncertainty and resource delay uncertainties also have an effect.

But my testimony only deals with the resource components of the reserve margin, mainly the system of mix and to a lesser extent the resource delay question.

Q. You said that smaller units generally lower the reserve margin, why is that?

A. The reason basically flows from mathematics of relatively simple levels of probability theory.

Extreme conditions tend to be what drives the need to have a reserve margin; for example, having several large units out all at the same time.

Extreme conditions are much less likely if the possibilities of outages are spread over more units. For example, if we were to look at the probability of losing 40 non-utility generators or with the same size as a single nuclear plant, that probability would be almost zero that you would lose all of them. Whereas, the nuclear plant may have a forced outage rate on the order of say 5 to 10 per

cent. So that as you spread your resources over smaller individual resources, probability theory would suggest that the extreme, the probability of extreme events declines dramatically and the reserve requirements decline.

Q. Okay. I don't want to go into your methodology in detail, but perhaps you could describe briefly what you did as part of the study?

A. My first step was to prepare Exhibit 162, which was brought to your attention in some of the cross-examination of Ontario Hydro, and which is appended to this testimony. That exhibit essentially is the simple probability model that lays out the mathematical theory that would support the point that I am making here.

Our next step then was to prepare and conduct a modelling experiment to show and quantify what the real effects were on the Ontario Hydro system. This experiment used a production simulation and reliability model called PROSYM which our firm has used for a number of years and which has been validated by the California Public Utilities Commission. But the choice of model for this experiment is not terribly important.

We input into the model a representation

of the Ontario Hydro system. The particular representation that we used in this modelling was largely from the original DSP filing with some minor modifications, because we devised the experiment at that time.

We established that the best way to conduct this experiment was to model the year 2011 because the system was largely in load resource balance at that time. There didn't appear to be any significant surpluses, and because the first nuclear station that was contained under Ontario Hydro's original Plan 15 had largely reached maturity by that year.

So then we set up a simple scientific experiment using the model. For the base case we included this first nuclear station. We then conducted a substitution where we removed that nuclear station and replaced it with NUGs and we developed six representative scenarios which relate to the size and the reliability of the NUGs that were replacing the nuclear station.

What I want to emphasize again for you is that this testimony is reporting the results of a scientific experiment using utility simulation models.

I have received some interrogatories from

some parties which seem to appear that this is IPPSO's plan or something of that sort. It's not. It is just an experiment which was carefully designed to achieve one purpose which is to quantify and measure more accurately the effects of NUGs on system reliability, and to essentially flesh out the hypothesis from Exhibit 162.

The results of this experiment then allow the improvement of system reliability from NUGs to be properly considered by this Board in its overall planning and properly considered by IPPSO in the development of the remainder of its case.

Q. Mr. Marcus, why did you use nuclear and NUGs as the interchangeable options in your experiment?

A. There were basically three reasons: First, the nuclear units are the largest units on the system and therefore would tend to show these size effects somewhat more clearly than if I had chosen the smaller option. So it essentially shows the magnitude of the effect a little more clearly.

The second is that nuclear plants of the 4 by 881 megawatt design have the potential for common mode outages as well as outages of units which are independent of each other, and these are interesting

issues which could be evaluated by the experiment and provide some more information. So that's the second reason.

The third is simply a practical consideration. We devised the experiment and did much of the initial work of putting it together before the DSP Update, and at that time Ontario Hydro was in fact specifically proposing to build nuclear plants.

I would point out, however, that with fossil units, particularly large sized ones, the same general results would occur, although of course any numbers would be somewhat different.

Q. Is the point of your testimony to say that NUGs should be paid more because they are more reliable?

A. No, it isn't. I believe in concept that NUGs should be paid more because they reduce the system reserve margin. But we actually looked at how Ontario Hydro proposes to pay NUGs. If you look at Appendix C of my exhibit, you will see that they are already paying NUGs appropriately. So this testimony is not recommending any additional NUG payments or anything of that sort, or any change to Hydro's avoided cost methodology.

The problem is that the impact of NUGs on

the reserve margin is not being appropriately accounted for in Ontario Hydro's system planning, and if the reliability planning were being done properly, as the amount of NUGs increased, the reserve margin would go down. So, we are basically trying to capture the value that Ontario Hydro is already paying NUGs for its ratepayers and for society.

MR. KINOSIAN: A. If I could comment on that. That has been done in California. Since the introduction of a large number of NUGs onto the utility in California, the utilities have dropped their target reserve margins by 2 to 5 percentage points, and at least one utility has indicated that that was due to the better reliability of the NUGs compared to the existing utility resource.

Q. Now, Mr. Marcus, before I leave this subject, have you had a chance to look at -- excuse me, just a second, Mr. Chairman.

Actually, Mr. Marcus, before I get to that. When you are doing a reserve margin calculation, you have discussed how you do reserve margin calculations and the concepts in your paper, should you include all possible risks of problems in the future in your reserve margin calculations?

MR. MARCUS: A. No, there are certain

issues and problems which should not be included in the reserve margin. For example, transmission and distribution considerations should not be included because they are not a problem that the reserve margin can solve.

Other potential scenarios which have very low probabilities but very high consequences, for example, some type of severe accident or government regulation, or change in public sentiment or a combination of the three that would require closure of a large number of nuclear stations at one time is something that not only is it of low probability, but it's something that the reserve margin cannot help because it would overwhelm the reserve margin; you would just impose costs without obtaining benefits.

So I would say there are certain things like that and like the transmission and distribution system that should not be considered in reserve margin planning.

Q. And in your calculations did you include any of those category of things in the reserve margin calculations?

A. No.

MR. SHEPHERD: Mr. Chairman, for the record, we are having some problem with the

microphones.

---Off the record discussion.

MR. SHEPHERD: Q. Mr. Marcus, do you have any comments on the evidence of Mr. Lanzalotta or Mr. Logan on reliability issues?

MR. MARCUS: A. I will tell you, my most important comment is that my testimony and their testimony do not analyze the same issues. As a result, the Board doesn't face an either or choice. You don't have to pick among the intervenors in making a decision because you can adopt my conclusions regarding NUGs and at the same time could adopt some or all of the conclusions brought forward by the other witnesses, and the results would be additive, not inconsistent. So you don't face a decision on which intervenor witness you agree with.

Both Mr. Lanzalotta and Dr. Logan suggest lower reserve margins at the present for somewhat different reasons, and I would not disagree with their general conclusions that the reserve margin today could be somewhat lower.

However, I would point out that while I have not run the numbers in great detail, both of these parties may not have fully analyzed nuclear common mode outages which may have some countervailing upward

effect.

Finally, I would comment on one statement made by Dr. Logan on page 16 of his evidence, that the only effects of the lower reserve margin would be to reduce the need for peaking units.

While I would agree that the lower reserve margin would clearly more significantly affect peaking units than base load units, I would not make such an absolute categorical statement. Rather, I would suggest that at certain times a lower reserve margin could also have other effects such as accelerating retirements or deferring the construction of base load units for periods of time, particularly as the first units are being added into the system.

So the difference with Dr. Logan on that point is basically an issue of degree rather than concept, but I would not make such an absolute statement.

Q. Okay. Mr. Kinosian, let me turn to you. Can you confirm that Exhibit 521 filed in the spring was authored by you?

MR. KINOSIAN: A. Yes.

Q. What is the purpose of your evidence today?

A. The purpose of my evidence is to show

that it is as important and complex to evaluate the existing resource system as it is to evaluate new resources.

It's possible that existing resources with significant incremental operating costs may not be cost-effective to continue operating and therefore may be prematurely retired. Thus, the review of existing resources is integral to planning for the future resource needs of the system, otherwise you may understate that the need for future resources by failing to accurately account for the premature retirement of existing resources.

Q. And what is the structure of your evidence, what is it that your evidence includes?

A. My evidence presents a case study of such a study of an existing resource to provide a context and an example for the evaluation of existing resources in planning for long-term resource needs.

Q. Could you briefly summarize the San Onofre 1 story that's described in Exhibit 521?

A. Yes. The San Onofre Nuclear Generating Station, Unit 1, commonly referred to as SONGS 1, at the time we performed this review was a 25 year old nuclear plant.

Q. Excuse me, let me interrupt you for

just a second. Could you describe how you were involved in this first?

A. Sure. I work for the California Public Utility Commission's Division of Ratepayer Advocates. That group, the Division of Ratepayer Advocates, although it's part of the staff of the Commission, presents independent positions and hearings before the Commission representing the interests of the ratepayers. I was the project manager for DRA and its lead analyst on the review of the San Onofre Nuclear Plant.

Getting back to what we did in our review of San Onofre. The utility believed that it needed to spend approximately $125 million on improvements to the plant to comply with regulations made by the Nuclear Regulatory Commission, the federal agency in the U.S. which regulates the safety of the nuclear plants. Because of that expected cost our Commission required Edison to present an analysis justifying those costs and showing that it would be cost-effective to continue operating the facility.

DRA then reviewed and critiqued Edison's analysis.

[9:53 a.m.]

In our review we found that the utility

had been optimistic regarding its expectations of the costs of operating the facility and the future reliability of San Onofre. In addition, we found they had been pessimistic regarding the costs of replacing San Onofre's power.

We also found that they had presented assumptions and policies which were inconsistent with those it was using at the same time regarding the forecasts of need for future generation and the prices which should be paid to NUGs in the State.

I should add that the San Onofre review was incorporated into the PUC's process for review in future resource needs and payments for NUGs.

So the review of San Onofre was done as an integral part of the review for future resource needs.

Some examples of the optimistic forecasts Edison had used regarding San Onofre were that it assumed that OM&A costs would increase at a rate equal to inflation, although historically the OM&A costs for San Onofre, as for many other nuclear plants, had increased at a rate much above inflation. In fact, in a separate proceeding where the utility was having its rates set for the following year, it itself had forecasted that the OM&A costs would increase at a rate

above inflation.

In addition, the utility assumed that the capacity factor for the SONGS 1 unit right would increase significantly from what had been experienced in the last, the most recent 10 years of its operation, although the utility was not planning to perform any significant modifications to the plant to improve its performance; it simply assumed that all the problems it had experienced would go away and no new problems would occur in the future and therefore the plant would be more reliable.

The utility also assumed that the problems it had experienced with its steam generators would go away and not occur again, even though all the comparable units of the same vintage of SONGS 1 had to replace their steam generators.

Some examples of the utility's pessimism regarding the costs of replacing San Onofre's power was they assumed a very high cost for natural gas in the future; natural gas being one of the primary sources of alternative power in California.

They also assumed that they would continue to incur high OM&A costs for the facility if it were to shut it down because it assumed that it would need to maintain the facility in essentially an

operating condition to comply with its licence from the NRC. Although we have demonstrated that a number of other nuclear facilities that had been prematurely retired were allowed to decrease their own OM&A expenses by obtaining a possession licence rather than an operating licence.

In addition, the utility failed to account in its analysis for the possibility of conservation programs or NUGs replacing part or all of the generation from San Onofre. It only evaluated the potential costs of the utility itself replacing the power from San Onofre.

Regarding some of the inconsistencies with its proposals and forecasts on San Onofre with those it used for other resources. The utility in discussing prices and contract terms that should be implemented for NUGs had asserted that all new NUG resources should be required to be dispatchable; that is, that the utility should have the ability to require the NUGs to increase or decrease their generation to match the fluctuations in demand on the utility system.

The utility asserted this was necessary because of an excess of base load or non-dispatchable resources on its system limiting the flexibility of its operation. However, in evaluating San Onofre the

utility failed to account for the fact that San Onofre itself is a non-dispatchable resource and is operated in a base load manner.

In addition, regarding NUGs, the utility proposed that no value be placed on fuel diversity benefits provided by NUGs. Whereas, for San Onofre, it asserted that one of the primary benefits of continuing to operate the facility would be to provide fuel diversity to its system.

Another example was regarding the transmission line losses of the facility. Edison asserted that although it had not performed a study, the San Onofre facility had a lesser amount of line losses than typical generation on its system. However, after it was agreed the plant would be shut down, the utility stated that any NUGs or other resources that would produce generation at the San Onofre site would in fact have higher line losses than a typical resource on the utility system.

Q. I take it from that that there was a substantial disagreement. Can you tell us what happened, the result was?

A. After we conducted hearings where both the utility and DRA witnesses were cross-examined on these issues, the utilities which jointly owned the

facility came to DRA and proposed a settlement which was later agreed to and adopted by our Commission wherein the facility will be shut down sometime -- actually right about now I believe.

Q. There was an interim step. Tell us about the interim step.

A. I'm sorry.

The results of our analysis as opposed to Edison's analysis was that it was not cost-effective to continue operating the facility. DRA concluded that continuing to operate the facility would end up costing ratepayers on the order of $500 million, present value. Thus, we recommended that our commission not approve the continued operation of the facility.

However, we realized that we might not win that point in the litigation so as a secondary recommendation we propose that if the Commission disagreed with our conclusions and instead agreed with Edison and its forecast that the risk of the future operation and costs of the facility should be placed on Edison and its stockholders rather than on ratepayers.

So, we processed a non-traditional rate-making treatment wherein Edison would get paid a price for San Onofre based on its own forecasts rather than a traditional rate making wherein all costs, no

matter what they turn out to be, are passed onto ratepayers.

Q. Is that sort of like a price per kilowatthour?

A. Yes. It would be a price per kilowatthour based on the amount of energy Edison forecasted the facility would produce and at the cost the utility forecast it would produce the energy at.

So if the facility operated as well and as cheaply as the utility had forecast, the utility would get, would recover all of its money, all of its expenses from ratepayers. If it operated better than it had forecasted, the utility would keep 100 per cent of any savings. If it operated worse, the utility would have to pay all the extra costs.

Q. Now given this background, in your view what would be appropriate conclusions for a Board like this one to draw from this SONGS 1 situation?

A. I would suggest that the Board should conclude that it is important to evaluate the existing resources if there is such a point in time where those resources have significant incremental costs of operation such as a need for significant capital additions or if environmental or regulatory rules change in a way which increase their operating costs.

Or, conversely, if the costs of alternative resources dropped dramatically or if there is a significant change in the availability of those resources, of alternative resources, and that a review of those existing facilities should be critiqued by a party other than just the utility because under current regulatory structures utilities have very little incentive to perform a detailed critique of their own resources.

Q. What does this mean in the context of demand/supply planning?

A. In the context of demand/supply planning, as I indicated at the beginning of my talk, an evaluation of existing resources which have significant incremental costs should be performed to determine whether or not those resources are likely to be available in the future so that you can accurately forecast what your future need for new resources will be.

If it is likely that an existing resource is not cost-effective and will be prematurely retired, that will directly influence the amount of new resources you will need to develop in the future.

Q. Thank you.

Let me turn to you, Mr. Marcus.

And perhaps we could start with Exhibit 740. Can you explain the background of that study.

MR. MARCUS: A. Certainly. The exhibit was prepared first for the OEB HR21 hearings and there are only some very minor modifications that were made in the process of updating it to bring it to this Board.

The purpose of the study in HR21 was not to draw specific conclusions but to raise issues to support the proposition that the Bruce "A" economics needed to be reviewed more thoroughly in an open public process.

Q. Can you briefly summarize your Exhibit 740.

A. The report was filed with this Board with a somewhat different purpose than the filing before the OEB. Essentially to make the point that Mr. Kinosian just made a few minutes ago that there are times when you need to look at the continued operation of resources that are part of the existing system for planning purposes and one cannot plan as if the existing system is a fixed quantity necessarily. It's not brought before you because Bruce "A" is part of the undertaking or anything of that sort; it's brought to essentially establish the baseline for evaluating the

undertaking.

My recommendation for a more extensive review of Bruce "A" has in fact been adopted in very significant part by Ontario Hydro's board of directors and by the Ontario Ministry of Energy last week. Because of that I will be quite brief in summarizing the report for the Board.

We first provide a methodological framework for looking at the economics of an existing resource such as Bruce "A". And the methodology is quite similar in structure to the one which Hydro had proposed and had done some evaluation of in the past.

We have reviewed the information on the public record in this hearing, asked some interrogatories at the OEB and got some more information, and identified six major uncertainties and several more minor ones which affect the economics of the continued operation of Bruce "A".

The six major uncertainties are: First, the capacity factor of Bruce "A" after rehabilitation, which essentially can be looked at as how much replacement power would you need if you were going to retire the plant? Or on the other side of the coin, how many kilowatthours do you get to spread the fixed costs over? So it's a major point affecting economics.

The second issue is the sources of power to replace the Bruce "A" generation and the amount of capacity required and the timing of that capacity. These are issues relating to the increasing level of surplus on the Ontario Hydro system. How one would have answered that question a year ago is very different than how one would answer that question today.

The third issue are future OM&A costs at Bruce "A" after the rehabilitation.

The fourth are future more routine capital modifications costs at Bruce "A" after the rehabilitation.

The fifth point are the costs of the actual work that is going to be performed at Bruce "A": the retubing of each of the four units, the rehabilitation work, and the potential need for significant steam generator repairs, and how those costs factor out.

And the last point of uncertainty is the valuation of environmental externalities; that is, the value associated with air pollution and other environmental effects from nuclear and fossil generation which is an issue you will be hearing about in some detail on later panels but it has some effect

on this decision because associating high environmental costs with fossil and low ones with nuclear would tend to give a different result than if environmental externalities were assumed to be either in reverse or low for all resources.

Q. Could you describe your report's conclusions on these six points.

A. We didn't reach any firm conclusions. The report was designed to identify issues and their potential impacts. We really didn't do Ontario Hydro's homework of looking at all of the uncertainties surrounding alternative assumptions.

In several areas we attempted to bound the analysis by showing some potential ranges of effects on the issues, but the purpose of the report was not to reach firm conclusions. And the data that were available I don't think were sufficient to reach firm conclusions. So, we didn't reach any.

Q. Well, then, did you form any conclusion as to what should be done with Bruce "A" nuclear generating station?

A. We identified three options. One is keeping it running. One is retiring each of the units at the time they would otherwise be retubed. And the third was an intermediate option that had not been

considered at that time which involved potentially mothballing the first unit and attempting to gather some further information.

But we didn't reach any conclusions on those issues other than that there was significant uncertainty and there needed to be the kind of public review that the Hydro board and the government have since announced.

Q. So, if all you have done is raised issues and haven't reached any conclusions, what should this Board conclude from your report?

A. Basically, I think again it's the same point that Mr. Kinosian made: that the existing system is not an immutable and fixed concept. There are times that you have to look at it with some amount of care at certain factors of it, especially when decisions to spend significant funds are going to be made.

And, further, that until a full analysis of Bruce "A" and its review have been conducted, it's not realistic to assume that Bruce "A" will be part of the existing system with 100 per cent probability and without some type of risk assessment looking at alternatives to that.

In fact, one may need, you know, some

lower level of risk assessment even if it is approved because of the potential that the performance might not be as proposed and that the last two units may still have some probability of retirement, although that probability would be likely to be lower if we had gone forward with the rehabilitation and retubing of the first two units.

Q. Are your conclusions then limited to commenting on the Bruce "A" situation?

A. No, they are not. I think the general principles that one has to be careful with the existing system and look at individual pieces of it at times when significant expenditures of funds are going to be made are applicable to all units. A thorough analysis may be needed in other different cases. For example, I agree with Mr. Koppe for the Municipal Electric Association that a complete and proper analysis has not been done regarding fossil life extensions.

Q. You filed a report on fossil life extension. What's that about?

A. As with Bruce "A" --

Q. Excuse me. Mr. Chairman, that's Exhibit 738. Sorry, Mr. Marcus.

A. Like Bruce "A", I think that the

purpose of that report was to point out the areas of costs where the decision on whether to extend the life of existing units or replace them. We pointed out the areas of cost where those decisions are likely to be sensitive.

We are not facing any decisions that are required to be made until somewhere in the later 1990s when we have to look at how many pollution control devices are installed on units that would affect the life extension decision at this time. So having a perfect answer to it may not be critical at this moment, but there are uncertainties.

However, with fossil life extensions, I believe that a general observation can be made to help bound and structure the analysis of them, which is again that the monetary evaluation of externalities associated with air emissions remaining after controls and the externalities associated with other forms of generation like nuclear, which is an issue again you will be hearing about in later panels, is likely to be extremely significant in dealing with this question is the Ontario context. It's almost the first fork in the analytical road of how you think about this question, if you will.

If we make a decision that externality

values associated with air emissions are quite high, then the difference in externality values between even a scrubbed coal-fired unit and a clean, modern, efficient gas-fired cogenerator or combined cycle, or for that matter even an integrated gasification combined-cycle unit such as Ontario Hydro is talking about, the difference in those values becomes significant and would tend to tip the scales toward retirement in many cases.

If the externality value associated with new generation is found to be low or zero, then economic effects would dominate. And in that case I would suggest that life extension of coal-fired fossil units is much more likely to be cost-effective but you would need to analyze it on a unit-specific basis for some of the reasons identified by Mr. Koppe.

THE CHAIRMAN: By who? Mr. who?

MR. MARCUS: Mr. Koppe from the MEA.

MR. SHEPHERD: Q. How does that sort of analysis that you are describing for fossil life extension compare to the analysis you described for Bruce "A" rehabilitation?

MR. MARCUS: A. I would say it's a very similar analysis. Some of the specific uncertainties are going to be different as was identified in the life

extension paper but you would have an analysis of very similar structure.

[10:15 a.m.]

MR. SHEPHERD: Mr. Chairman, that is our direct evidence. The witnesses are available for cross-examination.

THE CHAIRMAN: Thank you.

My first on the list of the cross-examiners is Energy Probe.

Ms. Malcomson?

MS. MALCOMSON: We are not available. We are hoping to be able to have somebody this afternoon or else have counsel maybe tomorrow, if that's all right.

THE CHAIRMAN: How sure are you about this afternoon?

MS. MALCOMSON: I won't know until I can contact our expert. I have been trying. It will be someone on staff to do the cross-examination. I didn't realize we are up to do it, so that's the problem.

MS. MORRISON: Apparently our correspondence did not get to Energy Probe, I am not sure why.

MS. MALCOMSON: We may have to forego altogether, it's probably not particularly important,

but I won't know that until lunch time.

THE CHAIRMAN: If you can find out as soon as you can, I would appreciate it.

THE CHAIRMAN: Mr. Watson?

MR. WATSON: Thank you, Mr. Chairman. You will be pleased to know that some of the statements that Mr. Marcus has made has actually saved me a little cross-examination in his reference to Mr. Koppe's materials.

CROSS-EXAMINATION BY MR. R. WATSON:

Q. One point of clarification, Mr. Marcus, dealing with Exhibit 739, your reliability exhibit, in your Executive Summary and in your conclusion, and if I could turn you first to the Executive Summary, the fifth paragraph.

MR. MARCUS: A. Yes.

Q. It's the paragraph starting using a conservative methodology.

A. Yes.

Q. The second sentence reads:

> NUG forced outage rates of 5 per cent and 15 per cent gives 7 per cent and 21 per cent reductions in resource reserve margins from nuclear levels respectively.

I understand that the 7 and the 21 values

should be reversed so that the sentence would read:

NUG forced outage rates of 5 per cent and 15 per cent give 21 per cent and 7 per cent reductions in resource reserve margins.

Is that correct?

A. That was a typographical error that was identified in MEA information response 19, yes.

Q. Mr. Marcus, still dealing with Exhibit 739, you used the PROSYM model; is that correct?

A. Yes.

Q. And as I understand it, your analysis shows that the load-meeting capability of a block of NUGs is greater than that of an equal block of nuclear capacity?

A. Using the 5, 10 and 15 per cent forced outage rates, that's correct.

Q. And as I understand it, your analysis is limited to deriving the load meeting capability of a block of a resource; is that fair?

THE CHAIRMAN: I'm sorry a block?

MR. R. WATSON: A block of a resource.

MR. MARCUS: That is what we looked at, was the load-meeting capability of specific resources,

which then feeds back into the analysis of the system reserve margin, but we did not derive a specific system reserve margin.

MR. R. WATSON: Q. That's my point, Mr. Marcus. Your analysis doesn't present this Board with any evidence on what the system reserve margin should be.

MR. MARCUS: A. It does not present any evidence as to the base case system reserve margin.

I would suggest to the Board that one would take whatever base case comes out of Mr. Lanzalotta, and Mr. Logan's and Ontario Hydro's evidence and the Board's weighting of it, and would reduce it by something on the order of 12 per cent for each NUG megawatt added at our 10 per cent forced outage rate scenario, for each NUG added beyond those at some point beyond such as 91 would be a way to do that. But the report certainly doesn't start with what the base case reserve margin should be.

Q. And your analysis doesn't extend that far. This is a suggestion that you are making to the Board. Your analysis doesn't go that far?

A. I think that the analysis that I have done, essentially if you look table -- I have to find the right table for you, Mr. Watson. If you look table

8, that essentially shows the difference between the overall system generation reserve margin of Ontario Hydro, which is something like 24 per cent, and the resource reserve margin of non-utility generation.

We also have the resource reserve margin of nuclear shown there, it's 14 per cent different than that. So that would be the type of issues.

DR. CONNELL: Mr. Marcus, your proposition that you reduce by 12 per cent per megawatt just doesn't make sense to me. Could you clarify that?

MR. MARCUS: Essentially that as you add a NUG, when you look at the reserve margin, you calculate it from some gross basis, Dr. Connell, and you say, well, our reserve margin would be 24 per cent because we have accepted Hydro's evidence or 21 per cent because we have accepted Dr. Logan's evidence, or what have you, and then you look at the number of NUG megawatts that are meeting that, and for each NUG megawatt that you have added you knock off .12 megawatts or 12 per cent.

DR. CONNELL: Thank you.

MR. R. WATSON: Q. Mr. Marcus, if you could turn to page 6 of your report, you will see the footnote at the bottom of the page starting with the words "PROSYM has been verified".

MR. MARCUS: A. Yes.

Q. That continues:

PROSYM has been verified for use in reliability modelling by the California Public Utilities Commission.

And as support for that you cite a document entitled "Reliability Indices and Rate making, A Comparative Analysis of Electric Utility Generation Reliability Models." Mr. Marcus, as I understand it, that was a report that was done by staff, that's not a Commission decision; isn't that correct?

A. It was a report that was done by the Commission staff under the provisions of Assembly Bill 475, that's correct. So it was verified by the Commission staff.

Q. But it's not a Commission decision?

A. No. It's essentially a report by the staff on reliability models.

Q. And as you are saying, it's a report by staff on reliability models, and as you indicate, all of the models that were tested were found to be accurate; is that correct?

A. Yes, that's correct. And I am in no way making a claim that PROSYM is a better model than anything else; I am just making the claim that it is

reasonable to be used.

Q. And one of the models that was looked at was the Frequency and Duration model, the F&D model that we have referred to in this hearing?

A. I think they looked, at least, at some variation on the F&D model. I am not sure that they looked at Ontario Hydro specific model. I believe that they didn't look at Ontario Hydro's specific model. They did look at models which have some of the same characteristics as the F&D model.

Q. The model which may have some differences incorporated into it by Ontario Hydro may not have been looked at, but the F&D concept as a computer model was looked at by the staff in this report; isn't that fair?

A. The concept was certainly looked at.

Q. Now, Mr. Marcus, turning to page 17, at the top of the page, in effect, your conclusion is that common mode outages reduce the load-meeting capability of a four unit nuclear station by about 444 megawatts?

A. Yes, that's correct.

And let me explain for just a moment to make it a little clearer.

What we did was we ran it and figured out

what the load-meeting capability after nuclear station was with zero common mode outage, and then ran it again at a half a per cent common mode outage, and that difference is the 444 megawatts that Mr. Watson referred to.

Q. Mr. Marcus, as you indicated, you looked at a four unit nuclear station with common safety facilities?

A. Yes. And other common facilities, and other common facilities similar to the existing 4 by 881 design.

Q. Yes. But isn't it fair to say, Mr. Marcus, that your conclusions and your discussion here does not apply to stations with units having independent safety facilities such as the 670 megawatt CANDU design?

A. I would say that my conclusion does not apply with such force, because the percentage of common mode outages would be significantly lower. But I can envisage some cases relating, for example, to step-up transformers and transmission systems which would still create common mode outages.

So I would say my conclusion would hold with much less force for that type of unit, but there probably is a much smaller probability of common mode

outage.

Q. Mr. Marcus, you indicated that you looked at three NUG outage rates that of 5 per cent, 10 percent and 15 per cent. As I understand your paper, you would agree that for the Hydro system, given the realistic mix of NUG projects that are likely to come on line, that the 5 per cent value is not appropriate?

A. I would say that if you are looking at a mix of NUG projects you should probably be looking at the 10 per cent number.

I disagree with Hydro on 15, but I believe 10 would be right.

If you were looking only at gas-fired cogeneration and combined-cycle NUGs specifically for some reason, then five would be right. But for the total mix of NUGs it wouldn't.

Q. And 10 per cent is more likely a figure from your evidence?

A. Yes.

Q. Mr. Marcus, you dealt with nuclear plant delays at page 17 of your Exhibit 739, there is a heading D, on-line date delays, and if you would look with me at the second sentence which reads:

> In its reserve modelling Ontario Hydro assumed in-service dates varied from six

months early to 12 months late, with an average of about six months late.

Now, if you could refer, please, to your Exhibit 211, which for the Board's assistance is at number page 23 of the attachments to Mr. Marcus' evidence.

Mr. Marcus, as I understand it, this is your analysis of delays which very simply concludes that Hydro is having increasing difficulty in bringing its units on line on time; is that fair?

A. Yes, the amount of delay has been rising over time.

Q. And as part of that exhibit you produced a table 1 which details the nuclear plants and the delays associated with the units in each individual plan.

A. That was the delays as of four years out, that is four years before the originally scheduled on-line date, and it was also based on what we knew about Darlington at the time that Exhibit 211 was produced, which I think was for Panel 3. So with those two caveats, that's correct.

Q. At the bottom of table 1 you produce two averages, one is the average of all units, that's 7.3 months delay, and the second is the average of all

units after Bruce "A", which is 11.2 months. Would you agree with me, Mr. Marcus, that if you excluded Darlington from the analysis, the average delay would be about 5.7 months?

A. I have not done the calculation.

Q. We can do it pretty easily, Mr. Marcus. All you have to do is take 7.3 and multiply by 20; isn't that fair?

A. Wait a minute. Hold on for just a minute. I would actually like to do this calculation.

Q. Okay.

A. That's about right.

Q. 5.7?

A. Without Darlington. But I would also point out that the dispersion in delays is somewhat different than Ontario Hydro had put in the F&D model even if the average without Darlington is 5.7.

There is nothing at six months early and there are a number of results that are well above 12 months. So you would reach the same expected value but with a wider dispersion around it.

Q. Mr. Marcus, if you could turn to page 2 of your Exhibit 739, the third full paragraph starts with the words "Ontario Hydro".

A. Yes.

Q. The paragraph reads:

Ontario Hydro claims that it pays non-utility generators for higher reliability than utility generation through the avoided capacity costs. We believe these payments are fair as discussed in Appendix C.

And you describe Appendix C and indicate that Hydro has not integrated this higher reliability into its planning exercises.

Now, Mr. Marcus, if you could turn with me to your Appendix C which is at page 24 of your Exhibit 739. If you have that, Mr. Marcus, you will see at the top of the page the first paragraph begins:

Ontario Hydro includes the full reserve margin in the avoided capacity cost.

And then in your second paragraph, you describe in numerical terms what that means. You indicate, in effect, that a NUG with a 5 per cent forced outage rate, with a 24 per cent reserve margin, receives 1.178 times the capacity value of a supply resource, and that 1.178 is simply the 95 per cent availability times 1.24; is that fair?

A. Yes.

Q. Now, what I would like to do, Mr. Marcus, is look at the effect of this current Hydro policy with which you agree on capacity payments, and let's apply that to a typical Hydro CTU, which I believe has a forced outage rate of about 9 per cent.

Now, you would agree with me that prior to the first major supply additions, Hydro's plan indicates that the supply resource will be a CTU?

A. Are you talking about for avoided cost purposes or are you talking about what is actually in the plan? I am a little confused.

Q. Planning purposes. Hydro plans to put CTUs on line before the first major supply additional is available.

A. I don't think that's true in the update median forecast plan. That's why I asked you the clarifying question.

Q. Let's just assume for argument sake that it is true, Mr. Marcus, and you would certainly agree with me under the DSP it was true?

A. Under the DSP CTUs tended to be built because of lead time constraints on nuclear stations.

Q. And let's look at the effect of this policy on a CTU. With a 9 per cent forced outage rate this typical CTU using the same calculation you have

put forward would receive .91 times 1.24, or about 1.13 times the capacity value of a supply resource. I notice you have a calculator there. I assume you have confirmed my figures?

A. Yes.

Q. And therefore, in effect, what we are saying here or what Hydro's policy is saying that a CTU would get 1.13 times the capacity value of a CTU?

A. I think that's not correct, because what we are saying is if you applied that to a resource mix strictly of CTUs the statement that you made would be correct. But the NUG resource mix is going to be essentially a mixture of resources of varying sizes and types, and the size being the most important issue, because to the extent that we are building units smaller than 168 or 336 or 672, there is a benefit to the system which is the benefit that we have identified here.

So, if you had a hypothetical case where all you were building were 336 megawatts CTUs as NUGs, that would be the result that would obtain that wouldn't be a terribly good one, but that hypothetical case is not terribly reflective of reality.

Q. What is reality though, Mr. Marcus, is the fact that we tend to get unusual results like

this, is due to the fact that Hydro's capacity SICs is too high. Isn't that the bottom line?

A. That Hydro's capacity what is too high? I didn't hear the word.

Q. I'm sorry. Hydro's capacity system incremental costs are too high.

MR. SHEPHERD: Excuse me.

Mr. Chairman, there was a debate about how far we are going to go in panel 1, and while I have no objection to Mr. Watson asking questions about costs and incremental costs, et cetera, perhaps this is an appropriate time to deal with the question how far do we go now and how far do we leave cost questions until later?

[10:32 a.m.]

As I say, I have no objection to Mr. Marcus answering these questions but Mr. Marcus will be back then to deal with cost questions.

THE CHAIRMAN: Well, this whole matter, as I understand it, deals with the adequacy or the appropriateness of the avoided cost payments to NUGs; is that correct?

MR. R. WATSON: This particular topic, yes, Mr. Chairman.

THE CHAIRMAN: Would that be better --

MR. R. WATSON: I can certainly explore that another day.

THE CHAIRMAN: Particularly since Mr. Marcus is going to be here. If he weren't going to be here then it might be worth asking him about it.

MR. R. WATSON: That's fine, Mr. Chairman.

MR. MARCUS: Mr. Chairman, if I might. I would just want to add the observation that the reason that we put Appendix C in here was simply to state that we weren't trying to get into the issues of how NUGs are paid. And that was essentially the reason for providing that information to you.

MR. R. WATSON: Q. Mr. Marcus, if you could turn with me to Exhibit 162. That's your exhibit on the effects of unit size on reliability and starts at page 7 of your attachments and continues to page 21 of your attachments to Exhibit 739.

MR. MARCUS: A. Yes.

Q. And as I understand in Exhibit 162 you are comparing the reliability of a large number of NUGs to a four-unit nuclear station?

A. Yes.

Q. Now you would certainly agree with me that reliability alone isn't the sole criterion on

which to choose between resource options?

A. Reliability is not the sole criterion. It's simply an issue that needs to be looked at along with a number of others, but it needs to be looked at carefully as we have been doing.

Q. And your analysis in Exhibit 162 uses an 8 per cent forced outage rate for NUGs, does it not?

A. The analysis uses -- essentially I used an 8 per cent rate basically so that we could look at the mathematics of it without getting into differences between NUG's and nuclear. Because there was an 8 per cent rate assumed for nuclear I used 8 per cent for NUGs simply to illustrate the mathematical principle.

If one used, for example, the 10 per cent that I believe to be the number that I would recommend out of my other material, I think the answer is not terribly different as you can see by comparing table 1 and table 2 on pages -- the marked pages 10 and 11. So, I used the 8 per cent as the base case simply so we wouldn't be talking about levels of reliability but we would be talking about the pure probability mathematics, but it doesn't make a lot of difference.

Q. But the difference it does make tends to overstate the analysis in favour of NUGs? It works

directionally in that way, does it not?

A. I would say if you used Exhibit 162 with an 8 per cent value, it would slightly overstate it and that slight amount would be quite small, but it would slightly overstate it.

Q. Now Mr. Marcus --

A. And that's one of the reasons I prepared Exhibit 739, so we could look at the numbers more purely using standard modelling techniques and get beyond the question of just mathematical theory.

Q. Mr. Marcus, in Exhibit 162, you provided a series of graphs. If I could refer you to graph 4 which is at page 21.

A. Yes.

Q. It shows a comparison of reliability between 80 NUGs and four nuclear units.

A. Yes.

Q. Is that fair?

And you are putting that forward to graphically illustrate your point that a large number of small units is more reliable than a small number of large units; isn't that fair?

A. That it's more reliable in the sense of having less probability of extreme event which are the types of things that drive reserve margins.

Q. Okay. And in trying to understand that graph, Mr. Marcus, and perhaps we can just take a second to identify it so there is no confusion, the top line which is very dark and goes along the horizontal line numbered 1 and then comes down at a very steep slope, that's the line for NUGs?

A. Yes. And that's essentially plotting the numbers on table 4 on pages 13 to 15.

Q. Right.

And the other line is the line for the nuclear unit?

A. Yes. And that's plotting table 5 -- the portion --

Q. The other part of table 4?

A. The other part of table 4 starting on page 15, right.

Q. And in looking at the difference between the two resources that you are examining, the NUGs and the nuclear unit, the significant part of this graph is the area between those two lines, is it not?

A. I wouldn't say that the significant part is the area between the two lines. I would not say that at all. I think the point is that it's the area between the two lines but it is not just some mathematical, let's integrate and find the area under

the curve. Because the point near the top of the curve are the extreme events that we have to worry about; whereas, the point near the bottom of the curve empirically as proven by Exhibit 739 doesn't have a great effect. So I would say the area under the curve is not, you know, calculated in some mathematical function, is not dispositive of anything.

Q. You would agree with me that what would be significant is if certain events or certain assumptions caused these two lines to move closer together or further apart?

A. Particularly at the top of the curve, that's correct. And I would emphasize the portion of the curve that's depicted here because that's the extreme events on which reserve margins are based. But that would be correct in concept looking at this top part of the curve that is shown here.

Q. And, Mr. Marcus, if your analysis and the results you produced in your table 4 hypothetically showed that nuclear units were more reliable than they actually are in your data, that would tend to move the nuclear curve closer to the NUG curve; isn't that fair?

A. In other words, just to give a concrete example, make sure I understand your question, Mr. Watson. You are suggesting to me if instead of

Ontario Hydro's figure of 8 per cent for nuclear forced outage rate, I had used 5, that's the type of thing you are suggesting?

Q. Yes. And that would tend to move the nuclear curve over toward the NUG curve?

A. That's true.

Q. Now in looking at the relationship between these curves, Mr. Marcus, isn't it also true that if instead of looking at one station, that's four units, you looked at two stations which are eight units, that would tend to bring the curves closer together as well?

A. Are you suggesting if one looked at eight units versus a specific number of NUGs?

Q. That's correct. Instead of looking at four NUGs you look at eight units.

A. If you were looking at 7,000 megawatts of nuclear and 7,000 megawatts of NUGs--

Q. Yes.

A. --the size of the single extreme event goes from one-fourth to one-eighth, so that would tend to bring the curve somewhat closer.

Q. Yes. And if you continued that comparison, Mr. Marcus, throughout all of the nuclear units or -- let me start over again.

If you continued that comparison from 4 to 8 to 12 to 16, that trend would continue, wouldn't it?

A. In the mathematics of this curve it would continue. But if you look at the results that we have on the load meeting capability of the resources, the empirical work in 739, I believe would largely hold.

Q. I want to get to that in a second but I want to ask you one more question before that, Mr. Marcus. In your analysis of your four units, you are looking at 881 units. If you substituted smaller nuclear units, that is 670 megawatt units, again, the trend that I am talking about would increase, wouldn't it?

A. The load meeting capability of nuclear for the same forced outage rate in a smaller size would be somewhat greater.

Q. So the reliability difference between the NUGs and the nuclear units that you are illustrating here would decrease?

A. By some amount it would decrease, probably a small number, but it would decrease.

Q. And Mr. Marcus, your analysis here has all dealt with one nuclear station and four units.

It hasn't looked at two stations or three stations, has it?

A. No, it hasn't.

I don't think anybody gets beyond two stations by the end of even -- of two mature stations by the end of Plan 15. Even so I don't think it would have been feasible to look beyond two in any event. So I would think looking at three would not be reasonable at all.

And I think that you can get the types of results in Exhibit 739 just by looking at one and that the effects would be similar spreading it out further.

Q. But you haven't done that analysis?

A. No.

Q. And you are just looking at the effect of one future station that might be added to the system and comparing that to NUGs?

A. Yes.

THE CHAIRMAN: Mr. Watson, would this be a good time to take the morning break?

MR. R. WATSON: I think it might be an excellent time, Mr. Chairman. If you will give me a minute, I might be able to tell you whether I'm finished completely.

THE CHAIRMAN: All right. I would be

glad to do that.

MR. R. WATSON: I am. Thank you.

THE CHAIRMAN: Mr. Rodger, you are next; is that right?

MR. RODGER: Yes, Mr. Chairman.

THE CHAIRMAN: And then the government; is that right? Ms. Couban?

MS. COUBAN: We have no questions, Mr. Chairman. Thank you.

THE CHAIRMAN: Thank you.

And then Mr. Hamer; is that right?

MR. HAMER: Yes. The airline lost Mr. Hamer's bag this morning and I am trying to find it right now. I will let you know if I find it.

THE CHAIRMAN: And then Mr. Campbell; is that right?

MR. B. CAMPBELL: Correct.

THE CHAIRMAN: Anybody else going to cross-examine these two witnesses? (No response)

All right. Thank you.

We will adjourn for 15 minutes.

THE REGISTRAR: Please come to order. This hearing will recess for 15 minutes.

---Recess at 10:45 a.m.

---On resuming at 11:00 a.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Please be seated.

THE CHAIRMAN: Mr. Rodger.

MR. RODGER: Thanks, Mr. Chairman.

Mr. Chairman, I plan to be very, very brief this morning given the answers given by the panel this morning and also by the answers to the interrogatories that AMPCO submitted last week.

CROSS-EXAMINATION BY MR. RODGER:

Q. Just to add one final question on the issue of cost and other matters, I take it, Mr. Marcus, from your testimony this morning that you would agree that in order to fairly give a complete comparison of NUGs versus any other kind of generation, whether they be large nuclear plants or otherwise, in order to have a fairer comparison you would have to look at the cost element of non-utility generation and the other option?

MR. MARCUS: A. If you were actually trying to do a plan or an alternative plan or sensitivities around the plan or something like that, you would have to do that.

Q. And would you also agree with me that you would also look at the mix of non-utility generation options to make that comparison?

A. I would agree with that to some

extent but perhaps not totally because it depends on how the non-utility generation options are priced.

So I would probably be looking more at the mix of contracts than the physical mix of NUGs, but I would agree that one would look to some extent at that type of a question.

Q. And you would also look at, among other things, the emissions that would be associated with particular NUGs in making that broader comparison between non-utility generation and other options?

A. You would look at a number of issues related to the environmental effects. One of the principal ones is emissions but it's clearly not the only one that you would look at on the environmental side. This is an Environmental Assessment Board and we need to be cognizant of that and look at those types of issues. But I would say it would be broader than just the emissions of NUGs versus the fact that nuclear doesn't emit any fossil fuel -- any of the same types of things that fossil fuels do.

Q. Now, in your evidence with respect to this reliability issue, there is a discussion on availability factors of various options. And would you agree that in order to compare NUGs to the base load nuclear case that you include in your evidence, you

would want to compare the availability factors of NUGs over a number of years compared with the availability factors for base load nuclear?

A. I don't quite understand the question. If you could try it again perhaps I can give you a better answer.

Q. Well, actually why don't I -- I have one interrogatory that AMPCO submitted to you and perhaps it would help if I went through that and that might help to illustrate my question.

THE CHAIRMAN: Now this is the first interrogatory that has been referred to and I guess we should now establish a system for how we deal with intervenor interrogatories.

MR. RODGER: Mr. Chairman, Ontario Hydro did give this a separate number. I don't know if you wanted to use that or have that for the record. But, when we submitted the interrogatories, we also copied Ontario Hydro and they came back with their own numbering system.

THE CHAIRMAN: Is that the B14.24.2 that I see on this one?

MR. RODGER: That's correct.

THE CHAIRMAN: That's for the interrogatory. But this is for the identification in

the hearing. Remember in the panels, Hydro panels, we had an exhibit number for each panel and then they followed in order after that, the interrogatories that came in, so there was a cross-reference between interrogatories generally and interrogatories that had actually become part of the evidence at the hearing.

I would suggest that this be given the next exhibit number which is --

THE REGISTRAR: 781. So it will be 781.1, Mr. Chairman.

THE CHAIRMAN: 781.1. And that this will continue until the end of the informal Panel 1 which we are doing now. And then when we get into Panel 2 we will repeat the process. Is that a manageable way of doing it. I would ask Mr. Nunn that: Is that a manageable way of doing it?

MR. NUNN: Yes.

THE CHAIRMAN: All right. Anyone have any problem with that? No. We'll do it that way then. 781.1 --

THE REGISTRAR: That is 781.1, Mr. Chairman.

THE CHAIRMAN: Thank you.

---EXHIBIT NO. 781.1: Interrogatory No. B14.24.2.

MR. RODGER: Q. Perhaps, panel, just

before I get to this interrogatory response.

Mr. Marcus, in what panel will IPPSO be presenting evidence on costs?

MR. SHEPHERD: Mr. Chairman, my understanding is that costs will be dealt with in part in the options panels and in part in Panel 4, I believe, dealing with avoided costs and costing methodology.

As a general comment, Mr. Chairman, I wonder whether we should sort of agree at the outset that we don't ask the witnesses what the parties' cases will be --

THE CHAIRMAN: I think this way has worked fine. The question is asked and you then, if you think it's appropriate, you should ask if you can do that. I think that's the best way of doing that.

MR. RODGER: Q. Turning to the written question we put to IPPSO. The question reads:

> Please state for the period 2011 to 2015 the capacity factor at which the NUG units must operate to match the expected output of a base load 4 times 881 megawatt nuclear plant.

And the response in part is:

> The reliability model run was based

on the year 2011 only.

And my question is: Why would you only do the reliability model run for that one year?

MR. MARCUS: A. Basically because we had 4,000 pages of output to deal with in our controlled experiment. And trying to spread it out over more years essentially would have multiplied the volume of the task tremendously.

Let me add one more point on your question about 2011 to 2016. Is that upon review of my data set, the nuclear plant that I took out had a mature forced outage rate and maintenance outage rate in 2011 that would carry through over the remainder of the planning period because that was in fact one of the reasons why we picked 2011. Was that it was the end of the immaturity period of that specific unit.

Actually you would find NUG reliability would be better if we had picked a year before 2011 because the nuclear unit was immature. But I'm sure some people at the table would have said that was an unfair comparison and I would have agreed with them.

So with the exception that nuclear will have lower outages out in the far future due to things like retubing, at least looking at Ontario Hydro's assumptions these are the assumptions that Ontario

Hydro has made from 2011 to the end of the plant life except for retubing, so, I don't think it makes any difference in reality, sir.

Q. And certainly then you don't assume for the purposes of NUGs that they would have the same capacity factor for every year?

A. I wouldn't assume that either NUGs or nuclear plants have the same capacity factor in every year. What I would point out, though, is that to make reliability modelling tractable in any sense, one has to set up those models based on long-term averages. That's what Ontario Hydro does. That's what the Coalition did in their modelling. I'm pretty sure that's what MEA did in their modelling since it's in the F&D model. That's what I did in my modelling.

[11:10 a.m.]

It's the only way to make the data tractable, is to use -- if you are going to put in a base case assumption, recognize that sometimes you will be above it and sometimes you will be below it in individual years, but you use a base case for planning. And then you may do sensitivities of various sorts around it.

But I would suggest that while your statement is true, basically to do any kind of planning

you have to abstract from, you know, just year-by-year random variations as opposed to year-by-year systematic issues.

Q. And just to go on with the answer that you provided in the interrogatory, starting from the second sentence of the response, it states:

> The nuclear plant equivalent availability factor assumed in this analysis was 83 per cent based on Ontario Hydro's numbers. The NUG availabilities used in the analyses were 80 per cent, 15 per cent forced outage rate scenario; 85 per cent, 10 per cent forced outage rate scenario, and 90 per cent, 5 per cent forced outage rate scenario.

Am I correct, Mr. Marcus, looking first to the 90 per cent availability, that that form of non-utility generation would be cogeneration and CTU combined-cycle thermal?

A. That would be the type of units that would have a 90 per cent availability in large part.

Q. And for the 85 per cent, would I be correct when I say that that would be including biomass, hydraulic, and gas-fired thermal?

A. I think that if you were to use the

85, that would be essentially our number looking at a mix of NUGs, because biomass would come out at about 85. It could be seen as a mix of combustion turbine-based technology and hydraulic. Hydraulic is a little lower, combustion turbine technology is higher. So it essentially has a mix in it, the 85 does.

Q. There is a mix inherent in that number?

A. Yes. One possible mix was the one that I have showed in a footnote in my testimony that I referred to, and another AMPCO interrogatory and I think it was the interrogatory AMPCO/IPPSO 1R, and I may have just created a problem for Mr. Lucas here. But in that one I stated specifically that an 80 per cent thermal, 20 per cent hydraulic would yield the 10 per cent forced outage rate and 85 availability factor. And I also stated in that interrogatory that biomass-fired generation would fit under that scenario.

Q. And what about for the 80 per cent availability factor?

A. I didn't make any assumptions at all. I just used Ontario Hydro's number because that was what they have used. I just used that as a means of bounding the analysis.

Q. No. No, that was the 83 per cent.

That was Ontario Hydro's number for the nuclear.

A. 83 per cent was Ontario Hydro's number for the nuclear, 80 per cent is Ontario Hydro's number for NUGs.

Q. And from your interrogatories through Hydro or previous testimony you don't know what that number is in terms of its NUG makeup?

A. We have had some discussions with Hydro on specific panels. I think they were using it as more of a generic number. I think that one of the reasons they are somewhat lower than 85 is that they have some different opinions about cogeneration forced outage rates than perhaps we do. But other than that I can't tell you specifically what Ontario Hydro's NUG mix was that went into the 80 per cent, or even if their NUG plans are consistent or inconsistent with the 80 per cent. I can just tell you that's their number.

MR. RODGER: Those are all my questions. Thank you.

THE CHAIRMAN: Mr. Hamer, has your bag been recovered?

MR. HAMER: Yes.

CROSS-EXAMINATION BY MR. HAMER:

Q. Mr. Kinosian, as I understand the purpose of your evidence, is it to show that there is

an example in California of the need to evaluate critically utility promotion of one resource or another; is that correct?

MR. KINOSIAN: A. The purpose of my testimony was primarily to indicate that a critical review of existing resources may need to be done as an integral part of long-term resource planning so that you don't overestimate the availability of those existing resources.

Q. But you would also make the point, and I believe did in your paper, if not in your oral testimony, that it is important to evaluate critically any resource being promoted by the utility by reason of the environment within which utilities traditionally operate; fair?

A. Yes.

Q. And your paper describes some of the analysis that you and your colleagues in the DRA carried out?

A. Yes.

Q. And some of the conclusions at which you arrived in the DRA?

A. Yes.

Q. And you describe some of the positions which the DRA took as a result of that

analysis and those conclusions; correct?

A. Yes.

Q. And your paper describes not just the DRA's analysis, conclusions and positions, but your personal analysis and conclusions and positions; correct?

A. That's correct.

Q. And under the California regulatory system, am I correct in understanding that the DRA plays an adversarial role vis-a-vis the utilities?

A. Our role is to represent the interest of the ratepayers in proceedings before the California Public Utilities Commission. At times our positions are adversarial to those of the utility, at times we are in agreement with the utility.

Q. And in the SONGS 1 case your position was adversarial; correct?

A. We disagreed with the recommendation of the utility in that case, yes.

Q. So that you took an adversarial position?

A. Yes.

Q. And your personal role in that case was adversarial to the utilities, was it not?

A. Yes.

Q. And you say in your paper, if I can summarize it fairly, that the SONGS 1 example illustrates several propositions: One, that nuclear plants are expensive?

A. Yes.

Q. And that the maintenance and capital expenditures during the life span can be high compared to coal and gas?

A. That's correct.

Q. And that these factors can make it more expensive to operate a nuclear facility than to turn it off?

A. That's correct.

Q. And I take it that you wish this Board to conclude that SONGS 1 is a relevant example for consideration in assessing Ontario Hydro's existing nuclear generating stations?

A. The purpose of my testimony is not to say that every nuclear plant should be turned off or that every nuclear plant is not cost-effective.

Q. I appreciate that, but my question was, I take it that you would ask this Board to conclude that the SONGS 1 example is a relevant example--

A. Yes.

Q. --for Ontario Hydro's system?

A. Yes.

Q. All right. And would you agree with me that nowhere in your paper, which has been marked as Exhibit 521, do you disclose the fact that SONGS 1 is a demonstration project?

A. SONGS 1 was originally built as a demonstration project, however, it has been operating commercially for over 25 years.

Q. And Ontario Hydro had a demonstration project at Douglas Point which was operated commercially for a number of years as well, did it not?

A. I do not know.

Q. So that you are not familiar with the Douglas Point example?

A. No, I'm not.

Q. And you are not familiar with the fact that Ontario Hydro just like So. Cal. Edison decided at a certain point that it would no longer operate that station for cost-effectiveness reasons basically?

Are you familiar with that fact?

A. Well, first to clarify one thing. Southern California Edison did not decide to stop operating SONGS 1 for cost-effectiveness reasons. It

has never stated its belief that SONGS 1 is not cost-effective --

Q. I said that. I said Ontario Hydro turned off Douglas Point for what it termed basically cost-effectiveness reasons.

A. I'm not aware of what they did in that case.

Q. All right. If I did say that the reasons were identical for both utilities, I misspoke myself.

What So. Cal. Edison did was enter into a settlement agreement with you; correct, as you told us?

A. Yes. It chose not to take the risk of its forecast being accurate itself. It chose rather to enter into a settlement to shut down the facility.

Q. And the deal that you gave them was to pay out their capital in a much shorter time than it would have been paid out in the ordinary course; correct?

A. Yes, with a lower return on that capital.

Q. But it was paid out much more quickly?

A. Yes, it was, which is the precedent the California Commission has established for

premnaturely retired facilities.

MR. MARCUS: A. If I might comment, I think it is also what Ontario Hydro has done in the case of certain abandonments in other cases, that they have tended to amortize them more quickly than they would have had had they remained in-service.

MR. KINOSIAN: A. I would like to add that the acceleration of the amortization also results in a decrease of ratepayer cost.

Q. Now, when you prepared your report for this hearing in Ontario, you used your testimony in California as the basis for this report; did you not?

A. Yes, that's correct.

Q. And in your California testimony you stated the obvious, which would have be obvious to the California regulator, that SONGS 1 was a demonstration project when it came on service in 1968.

A. Yes. And our testimony before the California Commission we went into a much greater discussion of the history of the SONGS 1 facility than I presented in my testimony here.

Q. Including the fact that it was a demonstration project?

A. Yes, though that never came up as a significant issue in the proceeding in California.

Q. But you included it in your testimony there.

A. I believe there is one reference to that, yes.

Q. And would you agree that SONGS 1 is not a typical example of nuclear generating stations world-wide?

A. In certain aspects it is comparable to nuclear stations world-wide, in other aspects it is not.

Q. In some other very significant aspects, wouldn't you agree?

A. Not for the purposes of my testimony.

The purpose of my testimony is to show that nuclear plants in general do have significant incremental costs of operations, and therefore are likely candidates for review for their cost-effectiveness. In that sense I believe SONGS 1 is comparable to most nuclear plants world-wide.

Q. Well, would you tell us, first of all, you will recognize that SONGS 1 is one of a group of similar Westinghouse stations located at various places in the United States?

A. Yes, in performing our review we looked at, I believe it was approximately 12 other

Westinghouse pressurized water reactors of a similar vintage and similar size to SONGS 1.

Q. Do you know what percentage of nuclear generating stations in the United States of the same vintage as SONGS 1 have actually been shut down for similar reasons or are subject to a firm decision to shut them down?

A. I do not believe any of the 12 units we reviewed in our analysis have been shut down, though I am not aware if any of the utilities or regulatory bodies have undertaken such a review to determine if they should be.

Q. All right. But you are not aware of anybody else having made a deal similar to the deal that you made on similar stations?

A. Not on similar stations, though in the State of Oregon the utility has recently agreed to shut down the Trojan nuclear power plant.

Q. Bad name.

And SONGS 2 and 3, which sit next to SONGS 1, are newer stations and have historically operated better than SONGS 1; correct?

A. That is correct. The DRA is currently undertaking a review of cost-effectiveness of those facilities.

Q. And at page 1 of Exhibit 521, in the second paragraph you say in the second sentence:

It began operation in 1968 and is well into the second half of its projected 40-year life.

In your California testimony you said, in fact, that it was one of a group that are all approaching the end of their operating lives; didn't you?

A. I don't recall that particular statement in my California testimony, but it's quite possible it's contained therein. I could search for it if it's an important point.

Q. You would agree that that would have been a characterization that you would have made, that SONGS 1 was approaching the end of its operating life?

MR. SHEPHERD: Excuse me, Mr. Chairman. Mr. Hamer is obviously quoting from testimony or purporting to quote from testimony in California. I think it would be appropriate if he provides the witness with a copy so the witness can refresh his memory and see the context and then answer the questions fairly.

MR. HAMER: I intend to cross-examine the witness in the ordinary way, Mr. Chairman, and if I

wish to contradict him with earlier documents, I will do so. But nothing that I have done thus far requires me to place his earlier testimony before him in my respectful submission.

THE CHAIRMAN: Well, you have asked him whether he said something in an earlier statement--

MR. HAMER: Yes.

THE CHAIRMAN: --and he said he might have and you are prepared to accept that answer.

MR. HAMER: Yes.

MR. KINOSIAN: I'm sorry, could you repeat your last question, please?

MR. HAMER: Q. The characterization of SONGS 1 as approaching the end of its operating life is not one with which you would disagree?

MR. KINOSIAN: A. No, I would not.

Q. All right. And in your Exhibit 521 filed here, I don't see you mention anywhere that SONGS 1 has potential problems which are unique to that station?

A. I did address in this exhibit the steam generator problems experienced at San Onofre, which, as you may characterize, are not unique to SONGS 1. They are an endemic problem in the nuclear industry.

[11:30 a.m.]

There were some specific problems regarding SONGS 1 involving the seismic conditions at the site. It is located near earthquake faults. And regarding the need to modify the unit to comply with the new NRC regulations. However, those problems were resolved at a point prior to what we were evaluating in our study.

Q. Well, my question was that nowhere in your paper do you identify the fact that SONGS 1 had potential problems which are unique to it?

And I noticed that you paused, along with Mr. Marcus, to review your paper and you haven't told us of any reference in your paper to any unique problems inherent in SONGS 1.

A. I do not believe I do indicate in this paper any specific unique problems with SONGS 1. And as I indicated in my previous response, most of the unique problems I am aware of with SONGS 1 were resolved prior to the period that we were evaluating in our review of the facility, so they were not essentially relevant to this analysis or this paper.

Q. Well, in your review of the facility you did tell the Public Utility Commission about the fact that SONGS 1 resides in an area which is

relatively prone to earthquakes.

A. That is correct. And as I indicated in my prior response, the seismic upgrades required by the NRC for SONGS 1 were completed prior to the period we were evaluating in our study.

Q. And you told the Public Utilities Commission that a large earthquake has the potential to result in outages at SONGS 1 and possibly prolonged outages for further modifications. The mere possibility of earthquakes can result in greater safety requirements. Wasn't that all the case when you were testifying before the Public Utilities Commission?

A. That was one of many potential problems which could have resulted in additional capital cost requirements for the facility.

Q. And not mentioned in Exhibit 521?

A. No. Nor did we mention many of the other potential problems which could result in higher capital costs for the facility. And as I said, the seismic problems is only one of a number of things which could result in higher capital additions for the facility.

Q. All right. And another problem unique to SONGS 1 is that it was essentially a test case for extensive tube sleeving within the steam

generator tubes; correct?

A. It was the first unit to have extensive tube sleeving performed on it. However, neither that nor the potential seismic upgrades were included in our cost estimates for San Onofre. Those were issues which we stated could result in even greater costs than what we were including in our study.

Q. SONGS 1 is one of the few if not the only facilities to have most of its steam generator tubes sleeved; correct?

A. That is correct.

Q. And that's what you told the California Public Utilities Commission?

A. That is correct. Though that was not a basis for any of our cost estimates in that case. It was simply one other point we were making which could result in even greater costs than what we have included in our study.

Q. It's a point you felt worthwhile making to the California Public Utilities Commission?

A. Yes, it was.

Q. And it's a point which you didn't mention in Exhibit 521?

A. No, it is not. There are many things in our study in California which were not included in

this paper. This paper was a summary of what was done in that case. It does not include each and every statement that was raised in the SONGS 1 proceeding.

Q. Now you say at page 3 of Exhibit 521, at the end of the first paragraph, that a typical nuclear plant will require over $1 billion in capital costs over its life after, underscored, it is built; correct?

A. Yes.

Q. And what data did you review in order to base that conclusion stated in Exhibit 521?

A. The experience in California regarding the SONGS 1 facility, as well as SONGS 2 and 3, indicate that the utility has, in the case of SONGS 1, spent more than $1 billion; and in the case of SONGS 2 and 3 forecast to spend more than $1 billion in capital upgrades on the facilities.

In addition, I have reviewed other documents such as the one cited at the bottom of that page which list average capital addition costs for nuclear facilities on an annual basis which if continued for the full 40 years of the facility would result in over a billion dollars typically for nuclear facilities and capital additions.

Q. And you say that that is a conclusion

which is based, first of all, on California experience and second of all on the public utilities fortnightly and did that refer to any data outside the United States?

A. No, that only addressed the cost of nuclear plants within the United States.

Q. So that you will agree with me, sir, that nothing that you have done in support of Exhibit 521 can be taken as being based on data typical to Ontario Hydro nuclear generating stations? You haven't reviewed that, have you?

A. I am not an expert on the costs of the Ontario Hydro facilities, no.

Q. And you have done no review of CANDU nuclear generating station capital modification costs, have you?

A. I have seen, in reviewing some of the annual reports of Ontario Hydro, significant costs included in their capital budgets for the nuclear facilities. In addition, I've seen at least one newspaper article referencing I believe it was a plan for $2.4 billion in capital upgrades to Bruce "A".

Q. And you will agree with me, sir, that that does not represent a systematic review of the data available with respect to CANDU nuclear generating

stations?

A. No.

Q. You agree?

A. I agree that it does not.

Q. And will you also agree with me that under the United States regulatory regime, at least in California, a utility has an interest in including capital modification expenditures within its rate base?

A. On the one hand it does because that will -- because the utilities, the investor-owned utilities in California are allowed to earn a profit on that rate base. However, to the extent that that, including those costs, increase its rates, it makes the utility less competitive in the marketplace, so there is also a negative impact to the utility to including costs in its rate base.

Q. Well, in general, do California utilities try to exclude things from their rate base or try to get it into the rate base?

A. If the utility has made expenses, it would rather include it in its rate base and get reimbursed rather than having its stockholders pay for it. However, it would also try to limit its costs somewhat to keep its rates competitive with other suppliers of electricity.

MR. MARCUS: A. If I might make a comment from my general experience in a number of these general rate cases. And there tend to come up issues of whether expenses should be capitalized or whether they should be expensed.

And I would, you know, certainly say that there is no uniform trend by utilities to try to capitalize items. And in fact in a number of cases I've seen the Division of Ratepayer Advocates try to capitalize things that the utilities wanted to expense.

So, I don't think there is a real uniform trend that ties into the financial condition of the utilities in any number of issues. They clearly want to recover their money somehow but whether it's rate base or whether it's expense, it's not clear that there is a uniform preference for one over the other.

Q. Mr. Marcus, do you have an example of a California utility having attempted to exclude from its rate base the kinds of expenditures which were at issue in the SONGS 1 case?

A. I have a similar example in the transmission case where a utility attempted in its -- where Southern California Edison in fact in its 1984 test year rate case attempted to expense a set of transmission upgrades. The Division of Ratepayer

Advocates said, don't expense this. This is a capital modification. Add it to rate base. So that's the type of example that I'm going on in making my statement.

Q. Not a nuclear station example?

A. No, it was not a nuclear station example.

Q. Mr. Kinosian, you will agree that once capital equipment on a nuclear facility has been replaced, that equipment can be expected to have a useful life of a certain number of years? Or an estimated number of years?

MR. KINOSIAN: A. Yes.

Q. And to the extent that it is now new once it has been added, that newness will affect the estimates one would make overall for repair and maintenance costs, would it not?

A. For that particular piece of equipment, yes.

Q. And if one adds a second new piece of capital equipment to the facility, that will have a similar impact on estimates of future replacement costs because that second piece of equipment is now new too? Correct?

A. That's correct. However, at the same time the other equipment in the facility, which hasn't

been replaced, is aging so that would also have an impact the other direction.

Q. Sure. Sure. But the more one replaces in the facility the greater the impacts one will have on estimates of future replacement costs; correct?

A. That's correct. Which is one reason why it's important to do a cost-effectiveness analysis early on in the time you are performing these capital additions so that you don't add a bunch of equipment and then perform your cost-effectiveness analysis after you have already spent a lot of the money.

MR. MARCUS: A. I would make another comment: that there are two types of capital additions at nuclear plants. There is replacing something that's old and is broken, which may have some of the effects that you are discussing; there also are adding equipment that was never there in the first place, which would tend to have some of the opposite effects of having increasingly incremental OM&A and decommissioning and other similar types of costs.

Q. And all of that is plant specific, is it not, Mr. Marcus?

A. I would say that when you are looking at an individual plant, you can get some information on

that. But when you also look at individual plants, you can see trends in what has been happening over time.

Q. And it depends on whether the individual plant is operating under the NRC regulatory requirements or some other country's regulator, does it not?

A. I would say in perhaps, only perhaps to the extent of how much betterment equipment is required, there might be some factor there.

Q. All right.

A. Because regulatory regimes do affect the amount of new equipment that was never there in the first place that needs to be put on.

Q. Exactly. Exactly.

Now, the SONGS 1 unit had operated over the past five years, at the time of your analysis, at less than 50 per cent capacity factor; is that correct, Mr. Kinosian?

MR. KINOSIAN: A. Yes.

Q. And you make the statement in Exhibit 521 at page 7, at the top of the page:

> Nuclear plants are routinely shut down for a period of months for refueling and to perform routine maintenance.

Correct?

A. Yes.

Q. Now should we put the word "California" nuclear plants or "United States" nuclear plants at the beginning of that sentence?

A. Possibly more accurately, non-heavy water reactor plants, which are the type used in the United States, are not shut down necessarily for refueling, though even the heavy water reactor ones will be shut down for routine maintenance.

Q. But not for refueling?

A. That's correct.

Q. And you say next:

> Because of this required downtime - referring back to refueling and routine maintenance - the maximum capacity factor for a nuclear facility is likely to achieve over a long period of time, is about 80 per cent.

And that statement again reads back to the previous sentence, does it not, refueling and routine maintenance?

A. That's correct.

Q. And you would agree with me then that your maximum capacity factor of 80 per cent is not directly transferable to the CANDU technology?

A. No, it is possible that the CANDU facilities, since they do not need to be shut down for refueling, could have maximum capacity factors slightly in excess of 80 per cent.

Q. All right.

And in fact if one were to look at world literature and data on capacity factors for nuclear stations, that would be relatively easily available, would it not? The data is relatively easily available, I think you say that somewhere in your paper?

A. Yes, it is.

Q. And would you accept that if one looks at recent lifetime capacity factors for nuclear stations worldwide, somewhere between a quarter or a third of them are over 80 per cent capacity factors?

I'm sorry. I'm told it's annual capacity factors. If one looked to recent annual capacity factors, one would find roughly a third or perhaps somewhere between a quarter and a third over 80 per cent capacity factors down to March of 1992. Have you done any such review?

A. I have reviewed a number of documents which contain one-year capacity factors, historic one-year capacity factors for facilities which indicate a number of plants having one-year capacity factors

over 80 per cent.

My statement here was not in regards to a one-year capacity factor but a longer period of time.

Q. All right. And are you familiar with the fact, for example, that Point Lepreau, a CANDU 6 station in Canada, has a lifetime load factor of 91.3 per cent?

A. I am not familiar with that facility.

Q. Or that Pickering 8 has 87.1 per cent?

A. Again I'm not familiar with the lifetime capacity factors of that facility.

Q. Or for Pickering 7 or for Bruce 5 or any of the Bruce units.

A. Not their lifetime capacity factors, no.

Q. But in any event you will agree with me that the SONGS 1 example which you placed before this Board is no basis on which to conclude that CANDU stations in Canada will have as a maximum capacity factor the figure of 80 per cent?

A. No.

Q. You would agree with me?

A. I would agree with you that the purpose of this exhibit in the statement is this

exhibit is not to indicate what specific numbers should be assumed for the CANDU facilities.

Q. Right.

And on page 6 of your report under the heading O&M costs, you make the statement:

> Compared to other types of power plants, nuclear facilities require large numbers of personnel to operate and have extensive maintenance requirements.

Correct?

A. Yes.

Q. And may I take it that that statement is not based on any review by you of Ontario Hydro's nuclear O&M costs as compared to its coal plant O&M costs for example?

A. That's correct.

Q. That's something based on your experience in California?

A. My experience in California as well as documents, a couple of which are cited in my report, which regard OM&A costs for nuclear plants in the U.S.

Q. Are you familiar with the publication Nucleonics Week?

A. Yes.

Q. And that is one of the commonly used

sources of data on performance history in the nuclear industry?

A. Yes.

Q. And the July 2nd issue contains this statement. I would ask whether you agree with it if you are able:

> Overall, U.S. utilities continue to improve nuclear's competitiveness in 1991, spending 3.85 per cent more total dollars for operating and management than in 1990 but 3.24 per cent less per kilowatthour. The average cost of a nuclear kilowatthour was 26.11 mills down from 1990's 26.98 mills.

[11:50 a.m.]

Are you familiar with those figures or figures like that?

A. I am familiar with numbers of roughly that magnitude for the OM&A cost of nuclear plants.

Q. In recent experience?

A. Yes.

Q. All right. And Nucleonics Week also in the same issue indicates that average 1991 maintenance costs expressed in mills per kilowatthour were 6.74 mills, as compared to an average of 7.05

mills, 1989 to 1991. Are you familiar with figures like that?

A. I'm familiar that that is the general range of costs, I am not familiar with those specific numbers.

Q. But are you familiar with that fact --

MR. MARCUS: A. Excuse me.

THE CHAIRMAN: Please let Mr. Kinosian finish his answer.

MR. KINOSIAN: I was finished.

MR. HAMER: I had another question for Mr. Kinosian.

THE CHAIRMAN: Ask Mr. Kinosian the next question.

MR. HAMER: Q. My question, Mr. Kinosian, is that you are familiar with the fact that for 1991 average maintenance costs for nuclear facilities declined from the experience over the three year period 1989, 1990, and 1991?

MR. KINOSIAN: A. No, I am not familiar with that fact.

THE CHAIRMAN: Now, Mr. Marcus, you had something you wanted to say?

MR. MARCUS: I think if you look at any

single year you can get into some very interesting numbers. And let me make an observation, you can get both higher kilowatt hours and lower maintenance numbers if you have a different number of refuelings in one year than the other.

Nuclear plants are not refueled once a year in the United States. So you could get a trend that would go down like that if you had more refuelings in 1990 than in 1991 because you would have lower maintenance and more kilowatthours.

I am not stating that this is the case year here, but I would caution against reliance on single year data, because it has the potential for having some embedded biases like that in it, without quite a great deal of further information that has not been put before us.

MR. HAMER: Q. You would agree though, Mr. Marcus, that the refueling on a single station in the United States would not tend to affect the experience on average for all U.S. stations very much?

MR. MARCUS: A. For a single station it wouldn't effect it, but I don't know whether the data might have 10 more refuelings in 1990 than 1991. There is no information on that, we are just handed and asked to accept a group of numbers here that don't have any

basis behind them that we can look at questions like that.

Q. I don't think we want to get into an argument, Mr. Marcus, so we will carry on.

Can you tell us whether you have any data, Mr. Marcus or Mr. Kinosian, to suggest that maintenance costs in 1991 were higher on average for U.S. nuclear stations than they had been during the period that I have described, 1989 through 1991?

A. I don't have any data on that subject.

Q. Thank you.

Mr. Kinosian, in your analysis for the CPUC you also dealt with system operability concerns, did you not?

MR. KINOSIAN: A. Yes.

Q. And that has to do with the dispatchability or non-dispatchability of various kinds of units; correct?

A. Yes.

Q. All right. And you took the view there that a dispatchable NUG had a certain advantage over a non-dispatchable base load unit; correct?

A. That is correct, and the utility itself took that position, took the position that a

dispatchable resource was more beneficial than a non-dispatchable resource for its system. It however neglected to apply that to SONGS 1.

Q. So you that you in the DRA and the utility were in agreement that dispatchability of NUGs was a valuable advantage?

A. All else being equal, a resource which gives you greater flexibility should provide some extra benefit to the utility.

Q. And a plan which calls for non-dispatchable NUGs would lack that advantage; correct?

A. Yes.

Q. And going back to capacity factors for a moment, you mentioned that you reviewed 12 different Westinghouse stations; correct?

A. Yes. They were units that Edison had identified as being the most comparable to the SONGS 1 facility.

Q. And you criticized So. Cal. Edison for comparing SONGS 1 to one group of those units, but not to the others which you felt were more comparable?

A. We criticized Edison for out that set of 12 plants that it identified as being comparable, to take only a subset of the best performing ones out of

those 12 to use as its basis for forecasting SONGS 1 performance.

Q. And the ones in the group of 12 that had the better performance were the more recent Westinghouse stations with two loop steam generating systems as opposed to the three loop like the SONGS 1; correct?

A. My recollection is they were all roughly of the same vintage. I'm not sure chronologically if that is exactly correct. However, the ones they did evaluate did have two steam loop generators three loop steam generators as did SONGS.

Q. So the utility's comparable group were all three loop steam generating plants; correct?

A. I think you have got that reversed. As I recall, they were all two loop and SONGS is three loop.

Q. Yes, you put it right.

And the ones that were two loop generating stations had lifetime capacity factors of between 71 per cent and 82 per cent; correct?

A. Yes, that's correct.

Q. Are you familiar with the fact that many of the older U.S. nuclear stations have undergone extensive retrofitting?

A. Yes.

Q. In response to regulatory requirements and just advances in the technology?

A. And also to do things such as replace steam generators which have decayed.

Q. And would you agree with me that in general the capacity factors following such retrofitting have been much better?

A. That was not the case with SONGS 1, for example. It underwent a number of retrofits in the early 80s and its performance in the late 80s was much worse than it had been in the 1970s.

Q. I am trying to move from the single example to broader experience. May we take it from your answer that you have done a comprehensive or systematic review of U.S. experience in general in that area?

A. One review I have done of the general conditions in the U.S. is for pressurized water reactors, a group of approximately I believe 70 pressurized water reactors in the U.S., the facilities less than 10 years of years had an -- averaged three year capacity factors approximately 5 per cent higher than the 40 or so units that were over 10 years of age.

Q. And did that study address the impact

of retrofitting?

A. No, it did not.

Q. I take it that you have done no such study on the impact of retrofitting in a comprehensive and systematic manner?

A. No, I have not. That was not an issue in the SONGS 1 proceeding as they were not planning to do extensive retrofits for reliability reasons.

Q. Thank you. Could we turn to your table at page 18 of Exhibit 521. As I understand this table -- do you have that have before you, Mr. Kinosian?

A. Yes, I do.

Q. The bottom line, as we all say, is that the DRA estimated that there would be a $495 million disbenefit to continuing to run SONGS 1?

A. That is correct, though the number we might use now would be higher since our Commission has modified the way it calculates air emission benefits. It would likely be a much higher number now.

Q. But that was the number that you put in evidence at that time.

A. Yes.

Q. And the way you got to that number

was to take So. Cal. Edison's figures which are set out at the top of that table and they had come to an estimated saving of a net $408 million by continuing to run SONGS 1; correct?

A. Yes.

Q. And what you did in the bottom half of the table was to adjust their numbers where appropriate; correct?

A. Yes.

Q. And, for example, if you disagreed with the capital cost estimates of So. Cal. Edison, you set out a negative figure there of $200 million; correct?

A. That's correct.

Q. And you disagreed with the replacement power savings, and that turns up in the lower gas price item of another negative $200 million; correct?

A. That's correct.

Q. And with respect to the air emission benefit, they had calculated a benefit of $421 million?

A. That's correct.

Q. And you said, well, that is fine, but there is some marine damage which you haven't accounted for so there should be a negative $5 million; correct?

A. That's correct. The California Coastal Commission is requiring Edison to perform a considerable amount of work to mitigate the marine damage and we allocated a pro rata share to SONGS 1 of the costs for those mitigation measures.

Q. And at that time you proposed no adjustment to the $421 million figure for air emission benefits?

A. No, we did not.

Q. And it's fair and appropriate in assessing the cost-effectiveness of a resource to take account of air emissions or lack thereof, along with a host of other factors; correct?

A. Yes, and that is the process the California Commission has adopted.

Q. And would you agree that estimating the cost of non-air emission damages to the environment is, at best, a tricky business?

A. Which is one reason why we did not attempt to do so except in the specific case where there were direct costs required of Edison to perform mitigation measures.

Q. But you will agree with that statement that it is a tricky business to estimate the cost of non-air quality damage to the environment?

A. Yes. It's also very tricky to estimate the cost of air emission damage as well.

MR. MARCUS: A. I think that uncertainty in an estimate is not a reason to necessarily assume that zero is the right answer for it. I don't think it was needed in Mr. Kinosian's analysis. But I don't think that uncertainty should be confused with a zero impact.

Q. But I take it Mr. Marcus, that you would agree with Mr. Kinosian that it is a tricky business?

A. I wouldn't use the phrase "tricky business". I would say it has a higher amount of variability around the estimate.

Q. Mr. Kinosian, you would use the phrase a "tricky business" because you used in your California testimony; would you not?

THE CHAIRMAN: I think he has already said that.

MR. HAMER: All right. Thank you.

Q. And for example, the work done in places like Pace University on figures for externalities has produced starting point figures but not definitive answers; correct?

MR. KINOSIAN: A. That was what was

indicated in DRA's report. We discussed the issue of other environmental impacts and presented to the Commission one source of estimates on those damages that we were aware of, though we did not include those values or recommend that those values be used in the analysis since, as you said, it's a tricky business.

Q. Thank you. Now, the two biggest disagreements that we see on your table 1 with the utility's position had to do with capital cost modifications and gas prices; correct?

A. Yes, those are the two single largest factors.

Q. And the significance of the gas prices, as we read in your report, was in estimating the cost of replacement power for SONGS 1?

A. That's correct, given the way the utility had done the overall analysis, as I said earlier, limiting replacement choices to resources the utility could provide rather than, say, NUGs or conservation programs. Natural gas-fired resources were one of the primarily replacement resources.

Q. And it was your view that for purposes of the SONGS 1 cost-effectiveness analysis, So. Cal. Edison had made an error in its forecast of gas prices, they used the wrong forecast?

A. They did three different scenarios using three different forecasts. What we stated in our testimony was that the value they were using for the median forecast was in fact one that they were characterizing as a high forecast in other proceedings. So we recommended that the high forecast they use here for SONGS 1 should not be used at all, and that their median forecast be used as a high forecast rather than an median forecast.

Q. So to simplify, you were saying they were using the wrong price forecast in the SONGS 1 analysis?

A. Yes.

Q. And you have done no study of gas price forecasts being used by Ontario Hydro for purposes of this hearing or for purposes of its current planning?

A. No. As I have said before, the purpose of this exhibit was not to provide specific numbers to use for analyzing the CANDU facilities.

Q. And the fact that So. Cal. Edison made an error in its use of the gas price forecast really doesn't tell us much about the Ontario situation one way or another; does it?

A. Except to the extent that Edison was

being inconsistent in one proceeding saying that the forecast was a median forecast and another proceeding at the same time saying it was a high forecast.

Q. Does that tell us something about Ontario Hydro?

A. I think it provides some evidence that utilities which do not have accountability for the accuracy of their forecasts may be lax in the rigour they apply to their forecasts.

Q. And that would apply to quite a number of forecasts which a utility might use in its planning; correct?

A. Yes.

Q. Not just on gas prices, but on all sorts of things which are going to happen in the future that the utility attempts to predict?

A. That's correct. For example, I have seen documents which state that Ontario Hydro has consistently overestimated the amount of energy it will get from its nuclear facilities.

Q. And if one were to look at Ontario Hydro's present day projections on what it is going to achieve by way of demand management, one ought to be similarly skeptical, ought one not?

A. Yes.

Q. And you deal in your paper as well with transmission impacts. Would you agree that the evaluation of transmission impacts associated with a nuclear station is very much unique to the configuration of the particular transmission grid?

A. There are definitely many site specific impacts or site specific factors regarding transmission impacts; however, the general fact that nuclear plants operate in a base load manner so they will be filling the transmission lines constantly is more of a generic impact which would apply to essentially all nuclear plants.

Q. But you will agree with me that your discussion in Exhibit 521 is specific to the particular transmission constraints in which the utilities in California found themselves?

A. Even more specific than that, the transmission impact at the SONGS 1 site.

Q. Exactly. And the dynamics of those thick constraints don't tell us very much about Ontario Hydro's situation, do they?

A. I'm not familiar with the Ontario Hydro situation. It might be similar, it might not.

Q. Well, you are not telling us very much about the Ontario Hydro situation based on So.

Cal. Edison's transmission constraints?
A. That's correct.
Q. You deal as well in your paper with line losses associated with the nuclear station SONGS 1; correct?
A. Yes.
Q. And you say in your paper that DRA arrived at a $50 million estimate for the disbenefit of continuing to run SONGS 1 associated with line losses; correct?
A. That's correct.
Q. And what you told the CPUC is that that estimate came from a simplistic analysis; correct?
A. That's correct.
Q. And, in fact, your staff didn't have the capability of performing independent line loss evaluations.
[12:10 p.m]
A. That's correct. Though after the proceeding reviewing SONGS 1 was finished, in a separate proceeding regarding transmission impacts and how NUGs should be evaluated regarding transmission line losses and transmission costs, Edison produced estimates for all its substation sites including the San Onofre site; and the estimate Edison included in

that proceeding for the San Onofre site indicated that SONGS 1 would have higher losses as we assumed in our report of a general magnitude similar to what we estimated though the specific number would be different.

Q. All right. And you also considered it to be a benefit to eliminate a transmission bottleneck so as to permit the utilities to import power and energy from Mexico.

A. Either from Mexico or just increased exchanges between San Diego Gas and Electric and Edison itself or from NUGs that may be located south or north of the SONGS site. It would simply facilitate much greater purchases and sales.

Q. But one of the benefits which you describe at page 13 of your paper is removing So. Cal. Edison's inability to import significant amounts of inexpensive power from Mexico?

A. That's correct. My recollection is that they purchased a maximum of, I believe, 15 megawatts of power from Mexico and the SONGS bottleneck limited their ability to import more.

Q. And you though it was a good idea for them to be able to import more power from Mexico?

A. Well, let me put it this way. In a

prior proceeding regarding a potential merger of Edison and San Diego, Edison had estimated a considerable benefit to eliminating --

Q. I'm not asking about their views. I'm asking about your views.

A. Well, that was the basis for our statement, one of the bases -- or Edison's statements and their analyses in that other case was what we used to estimate the value of reducing bottleneck.

Q. Did you think it was a good idea for them to be able to import power from Mexico?

A. That would depend on the particular prices that would be available at a particular time. I thought it would be beneficial to ease the transmission bottleneck.

Q. So as to be able to import power at the right price from Mexico?

A. Yes or from other resources. Mexico being one option.

Q. And would you have assessed in reaching that conclusion the environmental characteristics of Mexican power generation?

A. Our Commission has not adopted a procedure for including the environmental impacts of generation in Mexico into the cost-effectiveness

analysis necessarily.

The way our Commission has adopted air emission values, they do not apply to out-of-state imports of a short-term nature. A long-term purchase from out of state would have some environment air emission benefits or disbenefits attributed to it, depending on the values used in those other states.

And as far as I'm -- I'm not aware of any particular values assigned for Mexico generation. That issue, as far as I know, has simply not been addressed by the California Commission.

Q. So you have no information on the environmental characteristics of those plants?

A. Well, I am aware that San Diego Gas and Electric, and I believe Edison also, have had discussion with the Mexican utility regarding the repowering the Mexican facilities in part to decrease the air emissions, to switch them from burning oil to burning natural gas and to decrease emissions overall.

Q. At page 16 of your paper, you have a section headed "Conclusion". And does that section set out the conclusions which you ask this Board in Ontario to draw from the discussion earlier in your paper?

A. Yes.

Q. And you asked them to accept that

nuclear plants are expensive to operate and that it may be less expensive to develop alternative resources and so forth rather than continuing to operate existing nuclear facilities?

A. My recommendation is that the issue be investigated. It is not recommended here that it would be more cost-effective to shut down every nuclear plant and replace them with other resources, but that the possibility exists in certain situations that it would be cheaper to shut down nuclear facilities.

Q. And that possibility exists as between competing resources of all kinds, both on the demand side and the supply side; correct?

A. Yes, that's correct. And, for example, it's fairly -- at least in California, it's very routinely reviewed regarding gas or oil resources which have significant fuel costs. Those are routinely reviewed to see if other resources would be less expensive. However, in the case of nuclear plants where it is not a fuel cost but instead capital and OM&A expenses, they are not typically reviewed for cost-effectiveness as compared to other resources.

Q. In California?

A. In California, yes.

Q. All right.

And would you agree that in performing the evaluation which compares these competing resources it's important to have all of the options compete on a level playing field?

A. Yes.

Q. Mr. Marcus, in your paper on -- which I think has been marked as Exhibit 738 on fossil plant extension, you have attachment A to that?

MR. MARCUS: A. Yes.

Q. Being air emissions rates.

A. Yes.

Q. And there you compare the rates for coal with rates for gas and renewable resources like hydraulic or wind?

A. Yes.

Q. And those are declining from the unscrubbed coal at the top to renewable at the bottom at zero?

A. That wasn't exactly how I was thinking about putting the table together but that's how it happened, right.

Q. And if we added a line for nuclear plants it would go at the bottom of the table as constructed, at zero as well?

A. It would go at the bottom of the

table. However, just to give a general caution in looking at externality values because --

Q. Which is not what I asked you about --

A. Right. But it would be there at zero but one would not conclude therefore that there are no externality values for it or in fact for some of the other numbered resources that have zeroes on them.

Q. I don't think anyone suggests that.

Turning to your reserve margin paper, which is Exhibit 739, is it correct that one of the basic points is that as between a large station and a small station, if you compare them one for one, the larger one requires a higher per cent reserve capacity associated with it than the smaller station?

A. I would say, I would say that all else being equal. And the reason I say all else being -- it doesn't even have to be equal, but all else being in the same general vicinity, because I could think of a small station with a 30 per cent reserve -- excuse me, a 30 per cent forced outage rate and resource outage rate and I could think of something like Niagara which, as a hydraulic station, would have a he very low forced outage rate even though it's large. So I wouldn't draw that general conclusion in

all cases. But all else being fairly close to equal, I would draw that conclusion.

Q. And as one moves from larger to smaller units, the percent reserve capacity required tends to decline, all else being equal?

A. That's in fact true.

Q. All right. And as well, if one has units that do not have common mode failures associated with them, that tends to reduce the capacity, the reserve capacity requirement?

A. That's also true.

Q. Right. So that if one were to eliminate shared facilities in future nuclear stations in Ontario and went to independent 881 megawatt stations, that would eliminate the need for a reserve capacity to cover common mode failures?

A. If the stations were completely independent, then you would be just looking at the difference in reserve capacity that we are talking about without the common mode failures, that's correct. I still think there might be a small residual for common mode failure for things outside the boundary of the plant for putting a number of them at the same site, as I told Mr. Watson, but I think it's a small number.

Q. And the same effect would be observed if you went from 881 megawatt stations down to 670 megawatt stations?

A. I believe I told Mr. Watson that also.

Q. That's probably when I was talking to the airline.

And your analysis has not addressed additions of single unit stand-alone 670 megawatt CANDU stations; correct?

A. No, it has not. It basically -- you could read it as addressing single unit 881s essentially rather than single unit 670s, without the common mode outage, but it does not address the single unit 670s.

Q. Excuse me a moment.

Would you agree, Mr. Marcus, that gas-based or fueled NUGs are reliant upon external supplies of natural gas?

A. Yes.

Q. They don't store gas; they take it as needed from the distribution system.

A. They take it as needed from the distribution system but I would not agree with you that they don't store gas because many of them will store

gas in the summertime for their winter uses through the gas distribution company storage tariffs.

They will have to pull it back through the distribution system, but it isn't always at the end of some long pipe from Alberta.

Q. But you have done no study of the gas storage capacity available in Ontario to NUG's, have you?

A. I have done no explicit study. However, across the street in the Ontario Energy Board, I have been involved in their gas least cost planning proceeding. And it is my understanding from dealing with the gas utilities that at least at incremental levels they can -- Union Gas in particular has quite a bit of ability to add storage incrementally as if and when needed. So I've not done the specific analysis that you are referring to but I do have some general information on the subject.

Q. Well, will you agree that if the transmission system from Western Canada were to suffer an outage for whatever reason, that would ultimately have an impact on the gas available to NUGs in Ontario?

A. I would agree that that would ultimately have an impact; but because of issues such as storage and so on, I believe that the impact

actually in the winter season when we care more about it, would be somewhat less than it might be during some of the off-peak periods.

Q. But it would have an impact?

A. If it were long enough and of a significant enough duration, it could have an impact. I have seen some cases where wells have frozen over for a few days and they have not gotten to the point of interrupting firm customers served by those wells. So I would say that it would take a fairly significant, almost a force majeure kind of outage to have that impact, rather than the type that we have been experiencing historically.

Q. So that would be one of the low probability events?

A. It would be a very low probability event since we haven't seen any of them.

Q. All right. And such an outage would affect, assuming it had an effect, would affect not just one natural gas-fired NUG but potentially a large number of gas-fired NUGs; correct?

A. Yes. Such a gas transmission outage would have a potential effect over -- if sustained for a long period of time would have that effect.

Q. And in effect that would be a common

mode failure within the gas-fired generating system, would it not?

A. Yes, it would. As I say, I haven't seen any of those to date but it would be one.

Q. And did your analysis take any account of the possibility of such a common mode failure?

A. No, it didn't. And I think the reason was for one of the same reasons that I offered in my direct evidence a little earlier this morning: that there are certain factors on which one is very careful to build the reserve margin which have significant probabilities of occurrence and where reserves can in fact be carried for them and there may be other factors which are somewhat less important. But I did not take it into account.

Q. And has Ontario Hydro taken it into account?

A. Not that I know of.

Q. You refer as well in your report to delays in nuclear stations coming on line; correct?

A. Yes.

Q. And that has a cost in terms of reserve capacity requirements?

A. Yes.

Q. And would you agree that it would be a good idea to reduce unnecessary delays in having stations come on line so as to reduce the cost associated with the reserve capacity as you have just described it?

A. I think one can make that statement in principle, but we need to step back and look at what the data are that we are referring to. We are referring to data and information in Exhibit 87 from Ontario Hydro regarding delays four years from the date when you first expect a unit to come on line. We are not talking about delays early in the planning process.

I think it would be -- you know, certainly after four years the utility has the ability to respond by building generation or acquiring generation from NUGs or increasing DSM or something of that sort, so that delays, for example, eight years before the in-service date don't have an effect on the reserve margin.

I think it would be better to try to figure out how to do that within this four year window. But what I'm suggesting to you from the evidence that we have is that it is very hard to do that and in fact it hasn't worked terribly well over the last 20 years.

Q. Would you not agree that in utility

planning it's not a good idea for us simply to repeat history but to attempt to improve on past experience?

A. I think one always should work to improve on past experience in various ways. The question is how successful have we been in improving on past experience in the past and so forth.

Q. And for example in the nuclear area, one way in which utilities in the United States and others involved in the nuclear industry have attempted to reduce on-line delays is through the mechanism of upfront licensing; correct?

A. Essentially the utilities have been very concerned about the operating licence portion of their situation because that has to be issued before the plant is operable and it has caused delays - in many case perhaps for good reason - but it has caused significant delays. And utilities are very concerned about that. To my knowledge that's a case that's again specific to the United States rather than affecting the Canadian circumstances significantly.

Q. Well, the vendors as well of nuclear facilities are promoting upfront licensing, are they not?

A. They certainly are because it would make their technology a little more certain in the

United States.

Q. Which is not a bad idea.

A. I'm not really qualified to give you a conclusion on that as an expert on nuclear licensing procedure. I can give you a couple off-the-cuff comments that when a utility installs half of its plant backwards and has some difficulties with meeting its earthquake requirements because it has installed half of its plant backwards, that an operating licence is a very good safeguard.

But I can't give you a cost/benefit analysis or anything of that sort that would say, here is a case when you ought to have -- you know, here are circumstances when you should or shouldn't have them. And I am not prepared to draw any general conclusions on it.

Q. But you will agree with this general conclusion that delay for the sake of delay is not a good idea?

A. If delay occurs and nothing is gained from the public health and safety or I would also add, significantly, perceptions by the public of their health and safety rather than just -- because I think that is an important aspect, then nothing is gained from delay.

Q. And would you agree as well that efforts to have engineering complete in a nuclear facility before the start of construction can contribute to reducing delay?

A. I would say that it would have some potential for contributing to reducing delay, although I cannot to say how much and I cannot say how much would fall within this four year window that we are all talking about from the point of view of the reserve margin.

Q. But to the extent that one can promote measures whereby engineering will be complete before the start of construction, thereby reducing delay, that's a good idea; fair?

A. Without any information on other balancing factors I can't draw a conclusion. From the information you have presented me, I would have to agree with you, but it's not clear that I have enough information to answer the question, so I think I will step back from it.

[12:30 p.m.]

Q. And modularization is another development which vendors in the United States are looking at in relation to nuclear plans to reduce delay?

THE CHAIRMAN: Could we stop now? Is that possible?

MR. HAMER: That is fine.

THE CHAIRMAN: And if we could come back again at quarter to, quarter to two. 1:45.

THE REGISTRAR: Please come to order. This hearing will adjourned until 1:45.

---Luncheon Recess at 12:32 p.m.

---On resuming at 1:50 p.m.

THE REGISTRAR: Please come to order. This hearing is again in session. Be seated, please.

THE CHAIRMAN: Mr. Hamer?

MR. HAMER: Q. Mr. Kinosian, do I have it fairly summarized in my notes that in chief one of your main conclusions was that it is important to evaluate existing resources which may be subject to increased environmental regulation in future?

MR. KINOSIAN: A. That was one of many reasons why I indicated you might wish to evaluate closely a particular existing plant.

Q. And that is a valid concern when evaluating any resource, i.e., the possibility that it may be subjected to more stringent environmental regulation in future?

A. That's correct.

Q. Are you aware that in Ontario at present NUG developers are not subject to the requirements to undergo an environmental assessment under the statute which this hearing is taking place under?

A. I have no knowledge of what environmental requirements are made of NUGs in Ontario.

Q. All right. Well, accepting that to be true, that there is no requirement for environmental assessments at present, you would agree with me, I take it, that that is an important factor in assessing NUGs as a resource if there is a possibility that they will be subjected to environmental assessments in future. I see Mr. Marcus whispering in your ear.

A. It would depend at least from a ratepayer's standpoint on whether or not those an increased environmental costs are to be flowed through to ratepayers or whether or not the NUGs themselves will have to pay for any additional costs regarding environmental regulation. Whereas, with the utility plant the costs are almost always directly passed on to ratepayers.

Q. Would you fair of favour a system whereby NUG developers bore the risks of enhanced environmental regulation, or were permitted to flow the

increased costs through to the utilities who they are supplying?

A. In California any cost increases faced by the NUGs are borne by the NUGs themselves. The ratepayers do not bear the risks of an increased costs to the NUGs themselves.

Q. My question was, do you favour, could you answer that, please.

A. Yes, I was going to get to that. And that policy is one that the DRA has always supported and which I myself support.

Q. And you would agree with me that enhanced environmental regulation can have a serious impact on the economics of a NUG project?

A. Yes, just as it might on a utility plant, which might be one reasons why Edison felt it was not its interests to accept the risk regard San Onofre.

Q. Similarly, a NUG developer is going to have serious concerns if enhanced environmental regulation is imposed on his or her project?

A. I would imagine so, but I can't really speak for the developers.

Q. But it makes sense, does it not?

A. Yes.

Q. I thought you were speaking for NUG developers actually, but maybe not.

If NUG projects were subjected to best available technology requirements to mitigate or eliminate their emissions, that too would have a serious impact on their economics?

A. To the extent they have emissions, yes, it might.

Q. Particularly if they were unable to flow those costs through to the utility?

A. Yes.

Q. And that, as well, is a factor which should be taken into account if there is a possibility of enhanced emissions restrictions being imposed on NUG projects?

A. Yes. Once again, if the costs are to be borne by ratepayers rather than by the NUGs themselves.

Q. And you will agree as well that in addition to cost, an environmental assessment tends to delay rather than speed up the on-line date of a project?

A. Yes.

Q. Now, could we look, Mr. Kinosian, for a moment - and I hope for the last time - at your table

1. Do you have that?

A. Yes, I do.

Q. Looking at the air emission benefit of $421 million, that is a benefit that was anticipated from the continued operation of a 436 megawatt station; correct?

A. That's correct. Well, that is in part correct. That was the estimate for the air emission benefit for Edison's share of the generation which is 80 per cent of the 436 megawatt total.

Q. So if one were to take the whole of the station's benefits, the other 20 per cent being owned by the other utility, one would gross that up to something over $500 million dollars; correct?

A. Somewhere in the neighborhood of $500 million would probably be correct. However --

Q. Let's take $500 million just as a figure and perform some arithmetic on that. The $500 million is spread over 436 megawatts; correct?

A. That would be correct. However, as I believe I mentioned this morning, the California Commission has since revised the way it sets the air emission benefit.

Q. We will come back to that. Let's stick with my arithmetic of $500 million for the

moment.

A. Okay.

Q. And spreading that over 436 megawatts, would you agree with my calculation that that would come out to $1,146,000 per megawatt of air emission benefit?

A. Yes.

Q. All right. Now, as promised, let's come back to the revised figure which you say the CPUC has adopted for air emission benefits. And can you tell us what, under their revised attribution of benefit, SONGS 1 would produce by way of air emission benefit over the same period referred to in table 1?

A. I cannot give an exact number because the revision was made after the proceeding on SONGS was concluded, so we did not bother to go back and do a full recalculation. However, it would be well under $200 million.

Q. So it would be -- $200 million is a fair ballpark figure to substitute there; is that fair?

A. I would say likely somewhere between $100 and $200 million, in that general range.

Q. Just $100 million.

So we could say the substitute figure, could we say $150 million?

A. Fine.

Q. All right. And is that to be grossed up by 25 per cent or would that be for 100 per cent of the station?

A. That should be grossed up by 25 per cent.

Q. To produce, let's say, $190 million?

A. Close enough.

Q. All right. And dividing that by 436 megawatts we get $435,000 per megawatt of air emission benefit, would you accept that figure?

A. Yes.

Q. So that the current regime in California would apply a benefit of $435,000 per megawatt, and the regime applicable at the time of the example you have used in your evidence would have produced a benefit of $1.1 million-odd per megawatt of air emission benefit?

A. Yes. However, you can't really generalize these numbers. The values would be different depending on the type of operation of the facility. A base load resource, the way the prices were set in California typically would receive a much higher value per megawatt than a dispatchable resource would.

Q. Right. And in any event, taking those two figures as a rough rule of thumb or estimate, one could transplant those to look at the benefit that one gets from a larger or a smaller nuclear facility, could one not, because none of them produce SOx, NOx or CO(2)?

A. Well, these are the values that were established for California. I am not sure how applicable they would be to other locations.

Q. Well, accepting your premise that it's useful to look to California and to draw on California examples in Ontario, those would be the numbers that we would transfer to Ontario if we wanted a rough rule of thumb for air emission benefits of nuclear power generation?

A. That's absolutely incorrect. As I have mentioned a number of times, the purpose of my testimony is not to propose any specific values to be used for the plants in Ontario.

Q. Well, the only values that fall out of your testimony are those two values, correct, the 435,000 and the 1.1 million?

A. Those are the only two values that fall out for a base load power plant, Southern California Edison, serving Southern California Edison

with a 70 per cent capacity factor over the time period used here.

As I was saying before, you really can't generalize and apply these to other locations or to other types of power plants.

Q. You can't generalize on what to other locations?

A. These values and apply them to other types of power plants in other locations. The values were specifically derived for the individual utilities and the individual conditions in California.

Q. Let's stay in California. Let put me put this hypothesis to you. Let me hypothesize that California is looking at 3,000 megawatt nuclear station and attempting calculate the air emission benefit that would be associated with that station. If I understand your testimony correctly, California would take the figure of $435,000 per megawatt and multiply it by 3,000; correct?

A. No, it would not, it would do nothing of the kind.

It would look at what is being displaced by that 3,000 megawatts of nuclear plant, and based on the amount of emissions which are displaced determine what the total value is of those displaced emissions.

If that nuclear power plant is displacing primarily short-term purchases of out-of-state power, the value would be zero. If it was displacing primarily Hydro power, the value would be zero.

Q. And if it was replacing entirely fossil power the value would be as I have stated it; would it not?

A. It would be something comparable to what you have stated if it was displacing entirely fossil power located within certain air basins in California; however, even those values, even that might not be applied under currently proposed conditions wherein offsets may be used to reduce the amount of air emission benefits you would consider for a displaced resource.

Q. Let us not shift to what is currently proposed. Let us stay with what is currently applied. Will you go this far with me, sir, that if California were to look at a $3,000 megawatt nuclear station replacing entirely fossil capacity within California, it would come out to a very large dollar figure of air emission benefit?

A. Yes, it likely would.

Q. Thank you. Mr. -- I apologize, Dr. Marcus. I have been calling you Mister.

A. Don't call me Doctor because I'm not Dr. Marcus. You had it right the first time.

Q. Mr. Marcus, would you agree as well that if NUGs were to be subjected to individual environmental assessments, that would tend to delay rather than to speed up their on-line dates?

A. I think as a matter of general principle, that would be true. I think one of the reasons they are not subjected to individual environmental assessments is that individual NUGs tend to be relatively small projects in many cases. But if they were to be subjected to those types of assessments, that would undoubtedly be true.

Q. So that if, for example, the authorities were to decide that NUGs above a certain size should be subjected to an environmental assessment, on an individual basis, that would have an impact on their on-line dates; fair?

A. That would increase the lead time. The question is, there is a separate question which is whether it would increase the variability of the on-line dates which I think is more important to some of the questions at hand looking back at the purpose of my testimony which is reliability and reserve margins.

I think it's the variability which is

important. I can tell you the aggregate lead time would go up. I would expect there would be some change in the variability, but I cannot not estimate the magnitude; it could be very small, it could be very large.

Q. And that estimate, I take if from that answer, is not one which you attempted to do in your analysis?

A. We did not attempt to look at the consequences of moving all NUGs to individual environmental assessments because that is not the current policy. And, in fact, it's my understanding that for small hydraulic NUGs there is a class EA for them and I don't think that -- class EAs are meant in large part to the substitute for individual EAs.

Q. But in any event you attempted no sensitivities to determine the effect of various increased variabilities in the on-line dates of NUGs for that reason?

A. I attempted no sensitivities to increased variabilities of NUGs.

I also made some observations about nuclear. If you look at the bottom line of my testimony, I claimed virtually nothing for the reduction in on-line delays. So I think that it

doesn't make a whole lot of difference when you look at the bottom line results of Exhibit 739.

Q. And in your analysis, as I understand it, Mr. Marcus, one scenario involves 88 NUGs of 40 megawatts each, and another scenario involves 200 NUGs of 10 megawatts, and 10 of a 150 megawatts; is that correct.

A. Yes.

Q. Those are the blocks with which you replace the nuclear station in your two scenarios?

A. That's correct.

Q. And would you agree with me that on either of those scenarios, let's take scenario No. 1, you are going to have 88 siting procedures, however regulated, to undergo in order to bring those NUGs on-stream?

A. You would have to look at 88 sites in that scenario, certainly. I am not certain what the procedures would be. But the NUG developers would certainly have to acquire whatever approvals are necessary for 88 sites.

Q. On the other scenario there would be 210 sites to be selected and approved?

A. Roughly.

Q. And if environmental assessments were

to be applied to all of those, those figures would follow too unless there were a class EA?

A. Assuming your hypothetical it is true, that would be correct. And there is a class EA for water power under development, so I think the hypothetical is not fully true.

Q. I don't understand that remark.

A. There is a class EA that is in fact being -- I don't know its exact stages. I think a witness on a later panel could tell you exactly what part of the process its in. But there is a class EA for water power sites that is well through the governmental process.

Q. And if there were -- scenario No. 1 there would be 88 sites that had to be improved and prepared for the installation, and on scenario No. 2 there would be 210 sites to be improved and prepared for the installation?

A. I don't think I agree with that fully, because I think -- I think I agree with you in general principle you have to do something with the site, but I think you have something specific in mind with the term "prepared". And if you are looking at putting a power plant next to or inside an existing industrial facility, or at an existing dam that doesn't

have hydroelectric power, I think the term "prepared" has much less scope than one would think of if one were looking at, for example, trying to build something very large in terms of the way that people tend to use that term of art.

So, yes, you would have to get the sites ready, but I think that the process may be less extensive, much less extensive for most NUGs.

Q. But more numerous?

A. More numerous but much less extensive and perhaps even less extensive per megawatt. I'm not certain of that last fact.

Q. And there would be infrastructure involved with each of the sites?

A. There would be some amount of infrastructure.

Q. Which would vary on a site-specific basis?

A. It would vary on a site-specific basis and again it would tend to be less. If you are putting a NUG at an existing industrial plant, you have got gas lines, you have got power lines. You may have to make some changes to those gas and power lines, but you are not starting from something greenfield or from something where you have to put up major transmission

additions or something that sort.

So again the process, there are infrastructure improvements needed, but when you are looking at existing industrial sites, those infrastructure improvements may be quite limited.

Q. But would have to be done at many, many, different places?

A. Yes.

Q. And let's assume all these NUGs are gas turbine, is that what you assumed in your reliability analysis?

A. I didn't make a specific assumption. I made an assumption that there would be some level of gas turbine either simple or combined-cycle in conjunction with cogeneration and some level of small hydraulic.

Q. But there would be a turbine with any gas unit?

A. There would be an individual power generating facility including all of the electromechanical equipment necessary to generate power at each site, certainly.

Q. And that goes for hydraulic as well?

A. Certainly.

[1:10 p.m.]

Q. And there would be then a great many of those?

A. Yes, you would have to put in -- you certainly have to put in one of those for every plant you are building.

Q. And all of these elements where one multiplies the requirements from one site to many sites across the province involve cost, do they not?

A. There certainly are costs associated with both but I can't -- I'm certainly not willing to tell you it's cheaper to build it all in one 3,500 megawatt nuclear --

THE CHAIRMAN: He didn't ask you that. He just said it involved cost. And you say yes to that?

MR. MARCUS: There are costs certainly associated with any -- with building any power plant there are significant capital costs, I will grant you that. It's almost a truism in this business.

MR. HAMER: Q. And in the past utilities have found it cost-effective to concentrate their capacity say on one site or a few sites rather than a great many sites for cost reasons; isn't that so?

MR. MARCUS: A. That is one factor affecting costs --

Q. Just as --

A. There are other factors affecting costs --

THE CHAIRMAN: Just a minute. Please, please, please. Answer the question that you are asked. If you have something else to say, you can say it, but respond to the question that you are asked first.

MR. MARCUS: Yes, that is one reason why utilities have put generation at sites with large numbers of plants at those sites. There may be other countervailing reasons not to do that related to technological and other costs and relating to issues such as complexity and unit delay when you start building large amounts of generation all at once and all at one site. But the engineering cost side of the equation is one reason why utilities have done that.

MR. HAMER: Q. But my only point, sir, and perhaps we can get to the celebration outside if we could finish this off. My only point is that in installing many, many different units and gaining a reliability reserve margin advantage, one also pays some costs on the other side in the sense that one may lose some economies of scale; isn't that fair?

MR. MARCUS: A. Certainly there are a

number of cost factors on both sides of this ledger. I think that one would have a tendency of losing some economies of scale and that would affect costs in one direction, you're right. But there are factors which affect costs in other directions. For example, greater efficiency by being able to use steam twice rather than once in many cases; greater efficiency by being able to use a dam that is already there so you don't have to pay that cost like you do when you are building a large new hydraulic project. So there are costs and benefits on both sides of these equations and you have identified one of the costs very certainly but there may well be benefits on the other side of the equation. So I don't think the implication can be left that we are looking at costs without other reasons.

Q. And don't worry about my implications because I don't even know where I'm going. But we can agree on this: that your analysis presented today has not attempted a complete balance of all of those debits and credits?

A. As I said in my direct evidence this morning, the analysis I have presented today is a scientific experiment to look at one issue which is reliability, so that it is factored in properly in all of the later planning exercises. The purpose of it was

not to factor in these debits and credits. The purpose of it was to answer one very specific question about reliability.

And other panels and other people on IPPSO's side of the case will be talking about a number of other issues in terms of cost/benefits and other factors. But the purpose of this testimony was to conduct an experiment and we conducted the experiment. So, the purpose was not to balance and it didn't balance.

Q. Is that a yes?

A. Yes, we did not balance the costs and benefits of anything. We conducted a reliability experiment.

Q. Now, in your Bruce rehabilitation paper, which is Exhibit 740, could we look please at one of the attachments which is at a hand-stamped page 96 towards the back of that paper. It's a graph with a straight line going up to the right. It's entitled "Projections of Nuclear Capital Modifications".

A. Yes.

Q. And you will have gathered that my mathematical abilities are slight, so bear with me. Am I correct that the line which you have labelled 'Bruce "B" Regression' represents the results of your

regression analysis?

A. For the plant Bruce "B".

Q. Right.

And that analysis was based on a least square regression?

A. Yes.

Q. And the purpose of a least square regression is to produce a straight line which best fits a scatter of single points representing capital costs?

A. I would say that is correct as a general rule. If you look at the function that I used on the year variable where it only applies to years after year five, I, in effect, produced a line that has a kink in it at year five by doing it but it was a least square technique that was used to product that line with the kink in it.

Q. And it's your decision in advance to use the least square analysis rather than some other form of regression analysis; is that correct?

A. I would say that least squares are generally the --

THE CHAIRMAN: No, no, no. Again please. Was it your decision to use the least square analysis rather than another kind of analysis?

MR. MARCUS: I would say that it was because other forms of analysis tend to be used largely when we get into problems with least squares. And maybe we are having a little difficulty about terminology. I mean you have linear regressions. You can also make regressions of other forms, other functional forms if you want to.

MR. HAMER: Q. For example, one could decide that in the particular kind of data one is attempting to analyze, it would be appropriate to use a curvilinear regression analysis; is that correct?

MR. MARCUS: A. That's correct. And the reason I was having trouble with your question, sir, is that both of those are least square regression but you could use a curvilinear form.

Q. And I have some just diagrams to illustrate what I am about to attempt to question you on.

THE CHAIRMAN: We probably should mark that diagram.

MR. HAMER: Very well.

THE CHAIRMAN: Next number for exhibit?

THE REGISTRAR: The next exhibit number is 782.

---EXHIBIT NO. 782: Copy of Figure 10-4. Examples of curvilinear relationships found for scatter diagrams.

MR. HAMER: Q. And looking at Exhibit 782, Mr. Marcus, these are examples, are they not, of curvilinear regression analyses plotted on data points?

MR. MARCUS: A. Yes, they are.

Q. And you can see that the authors of this textbook have applied different kinds of analysis in different economic situations; correct?

A. Yes.

Q. And it would be possible for one attempting to do a regression analysis of the capital cost of modifying a nuclear station to decide at the outset that a straight line reconciliation of the scatter of points is not the appropriate form of analysis to apply, would it not?

A. That's in fact true. And let me tell you about the process I went through to get the particular fits that I have. I essentially started with a rather naive straight line with no kink in it at year five or 10. I looked at the data. I looked at the results. I looked at the characteristics of the equations. And I found that putting that kink in improved it greatly. I also looked at another form. Look at that graph, size Y of population and number of

generations down there. I looked at that form also and I found that that also fits the data quite well, but it would be a less conservative form for me to use in doing the type of analysis we are doing here because it would say costs would rise at some very rapid rate at the end of the period and outside the period I was estimating.

So I came back to the straight line with the kink in it after looking at the straight line and after looking at that size Y of population type graph because it was, it fit the data well and it was more conservative than the straight line in terms of projecting lower amounts of future capital additions.

Q. But from year five forward you have used a straight line and simply assumed that whatever happened in the past is going to continue to happen at the same time rate in the future; isn't that correct.

A. Regression analysis always - to the extent it is used for prediction - tends to do that, that's correct.

Q. And it would be possible for the analysts to attempt to reconcile the scatter points using a curve which changed direction partway through the curve?

A. It would be possible for the analyst

to do that, but if an analyst looked at data I have on table 2 and tried to do that, they would get a much worse fit than they would get out of either a straight line or that other graph that I was referring to. Yes, you could possibly do that but you would not get nearly as good a fit with the existing data.

Q. Well, I notice that we don't seem to see in your papers anywhere that the data is plotted out. Do you have that with you?

A. I have not plotted the data for each of the individual stations. You can see the average of the A units and the B units on figure 1 but I don't have the data for the individual stations.

Q. All right. Have you done that though?

A. No, I didn't plot it out. Rather than plotting it out, I looked at the residuals that I was getting in the regression equations.

DR. CONNELL: Mr. Marcus, if I understand table 1 correctly, the maximum number of data points would be 10 for the unit with the longest life; is that correct?

MR. MARCUS: Pardon me. Are you looking at figure 1 or table 1?

DR. CONNELL: I am looking at table 1 at

the moment. There are 10 entries under Bruce "B".

MR. MARCUS: That's the plant with the shortest life, Dr. Connell. We have actually got entries out to year 23 for Pickering "A", although you are missing the first five years of data for Pickering "A", so there is something like 18 data points for Pickering "A" and the first five years are missing.

DR. CONNELL: But the Bruce "B" line in figure 2 is based on the Bruce "B" data presumably?

MR. MARCUS: That's in fact correct. But the other line, the regression for all existing plants which is very close to that, is based on all, I think it is 56, of these data points which have data out to year 23. And the two lines tend to fit with each other quite well but that's in fact true, Dr. Connell.

DR. CONNELL: Just bearing down on Bruce "B" for a moment. If the unit with the longest life is 10 years, what is the shortest life in that group?

MR. MARCUS: I would say probably seven although I am not absolutely conversant with the on-line dates of the units without looking them up for you.

DR. CONNELL: And the discontinuity at year five then for one of the units you would only have two data points following that discontinuity?

MR. MARCUS: Not correct, Dr. Connell. The method that we have used to set these up are that the capital modifications costs are measured with year one being the first year that any unit is in service and the costs are measured on a plant-wide basis.

We used the plant-wide basis rather than the individual units. First, because that was the best data that Ontario Hydro had; and, second, because if you tried to do something with individuals units, there would be a large amount of common facilities that couldn't be readily allocated in any way other than arbitrary to individual units. So we used the station basis rather than the unit basis in all of these numbers.

DR. CONNELL: So if you take eight years after your first unit start-up, that reflects experience of the four units but at different stages of life?

MR. MARCUS: That, in fact, is true. It reflects the age of the station as being eight years but each of the individual units within the station have a different age, and some of them would be younger then others, Dr. Connell.

DR. CONNELL: Thank you.

MR. HAMER: Q. I don't have any other

questions in that area.

Just turn back one page, please -- sorry, two pages to table 1. On this table Mr. Marcus you have set out the dollars per kilowatt of installed capacity which has been spent on capital modifications; correct?

MR. MARCUS: A. Dollars per station kilowatt, that's correct.

Q. Would you agree with me that one factor which goes to the need for capital modifications in any industrial equipment is how hard that equipment has been run?

A. We can talk about what the definition of hard running is but I would say the concept is correct.

Q. Well, if I drive my car 50,000 miles a year as opposed to 10,000 miles a year, I'm running that piece of equipment harder at 50 than at 10; correct?

A. That's correct. I will tell you the only reason I was backing off from it is that if you did like I do and drive 20 miles to work each way on country roads and freeways and drive 15,000 miles a year, your piece of equipment might be run less hard than if you drove 10,000 miles a year all in

three-miles chunks with starts and stops. That was the only reason for my caveat. I'm not trying to be extremely difficult here.

Q. No, I appreciate that.

When a plant is operated at a higher capacity factor it would be reasonable to expect more to be spent on capital modifications than when it is run at a lower capacity factor, all things being equal?

A. I would say from my experience, which is somewhat limited but my experience with fossil plants, that that might not be the case because in fossil plants capacity factor is one variable but the number of starts becomes important in looking at, for example, their capital modifications, the number of times you have to start the thing up. And high capacity factors tend to be associated with low starts.

So, I would say there is some, there is some validity to that but there also is wear and tear placed on equipment from starting and stopping it and there also are capital modifications which occur for reasons other than wear and tear.

Q. But we can agree that the figures in table 1 do not reflect the extent to which the particular unit has been run in terms of capacity factor; fair?

A. That's true.

Q. And if the figures --

A. Let me make one more observation that might help this along. The capacity factor in any one year can be inversely related to the amount of money spent because it takes time to spend money. So you have to be very careful, even when using capacity factor, to look back over several years rather than just saying the capacity factor in year X is 65 per cent and the dollars spent is a hundred thousand dollars and do analysis of that sort.

Q. But you are agreed on the point that I put to you that these figures do not reflect the extent to which any individual unit has been run?

A. That's true.

Q. And if you were to present the figures in terms of dollars per kilowatthour, they would reflect the extent to which the various units have been run because they would be using units of energy rather than units of capacity?

A. That would be a possibility but I think it would be very tricky to do that for the reason that I just gave you. The time it takes to make modifications in many cases is time when the plant is not being run, so you couldn't do it in dollars per

kilowatthour of the year; you would have to do some more complex methodology that looked back over several years of operation and, you know, you would have to do quite a complicated analysis to sort that point out.

Q. Or you could work out the amount of energy that the plant has produced over its lifetime, could you not?

A. Yes. I think age could have been expressed in terms of kilowatthours as well as in terms of years, possibly.

Q. And you could look at the number of dollars that have been spent?

A. Yes.

Q. And you could get a figure of dollars per kilowatthour?

A. Yes, we could have done a regression in dollars per kilowatthour -- dollars per cumulative kilowatt -- using cumulative kilowatthours as the age variable if you wanted to do that. I'm not certain you would have gotten a result that was markedly different or of greater value, but you certainly could have done that analysis and used a different mechanism for measuring age.

Q. But in any event that's not an analysis which you did?

A. No, it isn't.

MR. HAMER: I am very much obliged to you gentlemen. Thank you, very much.

THE CHAIRMAN: Thank you.

Is there anyone else before Mr. Campbell?

Ms. Malcolmson.

[2:30 p.m.]

MS. MALCOMSON: Having been unable to find our lawyer or convince any of my colleagues to ask these, I will have to do that myself. I hope that doesn't cause any troubles.

CROSS-EXAMINATION BY MS. MALCOMSON:

Q. Mr. Kinosian, in describing the rationale for Hydro's support for independent power in the past, it has described the off-loading of risk from ratepayer to the developer as a potential benefit of independent power. Is that the same sort of principle you are advocating on behalf of ratepayers in the case of SONGS 1 when you recommended adoption of a requirement for developers to swallow their own cost overruns?

MR. KINOSIAN: A. Yes, essentially the recommendation we made in the SONGS case was that if the Commission did find the plant cost-effective to keep operating, that the utility should take the risk,

the utility stockholders rather than ratepayers for exactly those reasons.

Q. Good. Thanks.

And Mr. Marcus, if you were advising a South California Edison type investor-owned utility that operated in a regularatory regime in which cost overruns could not be passed on to ratepayers, would you advise that life extensions or the rehabilitations proposed by Ontario Hydro be undertaken?

MR. MARCUS: A. In that regime I would say one would have to look at a number of issues. And I would say in that hypothetical regime it would have to have quite a good return on equity to the developer to be undertaken, because that is a significant risk. So I can't give you a definitive answer as to what I would advise, but I can tell you that I would require a higher rate of return on equity under that regime than under the current regime for the developer to take that risk.

Q. Thank you. That's helpful.

In your view following the rehabilitation would any fossil or nuclear units considered for life extension by Hydro meet the thermal efficiency heat rate test that Hydro now applies to NUGs?

A. If no further work relating to steam,

finding steam uses at those plants were done, a few of them would slip in just under the top edge and might get 1 per cent benefit under the NUG test. None of them would be anywhere near what a preferred NUG is.

Unless somebody of course in the process of, since we are all in the hypothetical land of privatization, if in that hypothetical situation someone might have found a use for some of the steam or heat out of the back end of the plant that would make that answer different.

MS. MALCOMSON: Thank you. Those are all my questions.

THE CHAIRMAN: Thank you, Ms. Malcomson.

Mr. Campbell?

MR. B. CAMPBELL: Thank you, Mr. Chairman.

CROSS-EXAMINATION BY MR. B. CAMPBELL:

Q. Mr. Marcus, I have four brief areas I would to go into with you. The first has to do with your use of common mode figures in your reliability calculations. Now, as I understand it, you had a starting point where you calculated a 3.2 per cent figure for common mode outages for nuclear plants and you based those figures on the Darlington probabilistic safety analysis; is that correct?

MR. MARCUS: A. That is mostly correct. I also reviewed the fact that Ontario Hydro had about .2 per cent of four unit common mode outages and .2 per cent of two unit common mode outages in its own reliability indices. So I looked at that 3.2 percentage these other numbers from Exhibit 148.

Q. All right. And I take it you took the latter figures you mentioned, they were part of what you took into account in reducing that 3.2 per cent figure to .5 per cent.

A. Actually, I'm not sure that that's quite correct also, Mr. Campbell, because the nuclear panel told us in cross-examination that the accidents from the Darlington probabilistic safety evaluation were not included in the common mode outage calculations done by the system planners in Exhibit 148. So I would say, in essence, it's more additive.

Q. The point I am trying to make is simply this: That you have, as I understand it, judgmentally reduced, you calculated a 3.2 per cent figure and then you said, that's too high for a variety of reasons, which in my judgment means that it should be reduced to .5 per cent?

A. No, I don't think that's correct. I calculated a 3.23 per cent figure and a .4 per cent

figure both, and I said judgmentally I know that the 3.2 per cent is wrong because there have been twice many reactor years and this accident hasn't happened.

Therefore, I said we could take the whole ball of wax, the accidents and the other common mode outages that your system planners use and then turn that into .5 or 1.10, and that was judgmental.

Q. Can you tell me exactly then how you got the .4 calculation?

A. If you look at the top of page 10, you see the sentence: Exhibit 148 gives common cause forced outage, non-accident related outages, rates of 0.18 per cent for four unit outagesand 0.19 per cent for two unit outages. So that is where I got it and then --

THE CHAIRMAN: I am sorry, what page is that?

MR. MARCUS: Page 10, Mr. Chairman. It's in the first paragraph right at the top of the page.

And if you see footnote 12, it gave a calculation of the .18 per cent for four unit outages. It showed how I did the calculation to get from probability and number of days into the type of thing one would put into a forced outage model.

MR. B. CAMPBELL: Q. Let me check

something.

Have you made any adjustment in arriving at the .4 for coincidence of outage periods with winter peak?

MR. MARCUS: A. Since these are forced outages I have made no such adjustment.

If I were looking at maintenance outages like a vacuum building outage, I would do that. But Exhibit 148 identified these as forced outages, so it would not be proper to do that.

Q. Now, dealing with the second matter, you indicate on page 2 of your Exhibit 739 that Ontario Hydro has not integrated this higher reliability, that being the higher reliability associated with a larger number of smaller units associated with NUGs, into its planning exercises.

I wondered whether in reaching that conclusion you were that in dealing with reliability for instance in Exhibit 6 it is stated that the supply model used in those calculations considers the impact of such items as generating unit and non-utility generating reliability indices, that is forced outage rates, planned and maintenance outages, and that those figures were NUG-specific numbers?

A. I was aware of all of what you have

stated to me. Your modelling actually sets up the possibility of dealing with the question. It is just when you use a 24 per cent forced outage rate for each and every year, even when you are adding NUGs to the system, suggests to me that Hydro may be ignoring the results of not only my modelling but its own modelling on that point.

So Hydro did its modelling in the conceptually right way; it is just the results that came out turned into 24 per cent in each and every year after the first few, and I don't think that's correct under the circumstances.

Q. I agree that Ontario Hydro used in the end a 20 to 24 per cent range for the reliability reserve when it was actually putting together the plan, but you do recognize, I take it, that in putting together the supply model, including the supply side of the F&D model, there were specific indices used for different types of generators, including non-utility generation?

A. Certainly.

Q. You agree as well, I take it, that the reliability of NUGs has been appropriately reflected in avoided cost? I believe you stated that had in your evidence in chief.

A. Yes. The payments to NUGs for reliability in fact track the results that we found and I think are fair and reasonable.

Q. So as I understand your argument, it is not that Hydro is unaware of the reliability characteristics of non-utility generation or multiple small units, it is simply that you believe they have inappropriately exercised their judgment in picking the 20 to 24 per cent range to use in putting together the integrated plan?

A. I think that the judgment that should have been used should have reflected quantitative results which would cause the reserve margin to decline as more NUGs are added. And I would also make a comment that the resource mix does affect the reserve margin. So that changes from the plan, particularly changes in the direction of more NUGs, would also affect the reserve margin.

Q. Taking that general principle then I would like to turn right to my third topic, and if you could refer to your Exhibit 739, page 13, table 2.

A. Yes.

Q. Now, as I understand it, what is being posited in that table is the replacement of 3,524 megawatts of nuclear capacity, with 3,520 megawatts of

NUG capacity in the form of 88, 40 megawatt units; is that correct?

A. In scenario A that is correct, and scenario B is a slightly different block of NUGs.

Q. That's right. We are talking about with a 10 per cent forced outage rate which you spoke of earlier today.

A. That's right.

Q. Well, I would like to focus on the 88 by 40 megawatts, the 3,520, just take you through some mathematics, make sure I have understood this correctly.

Now, as I understand it, what you come to is that the 3,520 megawatts of NUGs replaces, as I say, the 3,524 megawatts of nuclear, with an increase in load-meeting capability or what you called load-carrying capacity of 371 megawatts?

A. That's right.

Q. If my math is about right, that is about 100 megawatts more load-carrying capacity per 1,000 megawatts, or if you want to do the exact calculation, you take 371 divided by 3,520, you get .105, which translates into 105 megawatts more load-meeting, load-carrying capacity per 1,000 megawatts of NUGs?

A. That in fact would be the results of the math that you have just done and I think the result is correct.

Q. All right. Now, to put that in some perspective on the amount of reserve, the per cent reserve, I would like to take that slightly farther. For instance, let's just pick a year, I have picked the year 2000, and if you keep your calculator handy you may want to check this as we go through. But if you take the year 2000, the planning firm load in that year is -- I will give you what I think I understand to be the exact number, 25,889 megawatts. If I start out with a 24 per cent reserve margin, 24 per cent of that figure is 6,213 megawatts. Do you agree with those mathematics so far?

A. I managed to hit the wrong button on the calculator, if you could give of give me the peak load number again, Mr. Campbell, I would appreciate it.

Q. 25,889.

A. Yes, I do.

Q. And then if we looked at a slightly different resource mix where 1,000 megawatts more NUGs were being relied on in the year 2000, the planning reserve could be reduced by, say, 100 megawatts, then the system reserve figure of 6,213 would be reduced by

100 megawatts, giving 6,113, shall we say.

A. Yes.

Q. All right. And at that point in calculating the system reserve margin, the 6,113 megawatts, to calculate the reserve margin is equivalent to 6,113 divided by our 25,889, and that would give a reserve margin of 23.6 per cent.

A. That calculation would be correct.

Let me just point out for the record and maybe we want to identify this, that I answered an MEA interrogatory with a large number of calculations similar to the one that Mr. Campbell has just put forward, MEA Interrogatory 3, it might be helpful for people to have available to them.

Q. Well, I think I am more or less finished with this, but if we want to give that one the right number...

THE CHAIRMAN: Do you know the number?

THE REGISTRAR: 781.2.

THE CHAIRMAN: And it is interrogatory?

MR. MARCUS: I marked it as MEA/IPPSO 3R when I sent it back to my counsel. I think it has got a formal number since then.

THE CHAIRMAN: It's got a Hydro number.

MR. B. CAMPBELL: The interrogatory No.

is B14.9.17. If that could be added to the list, Mr. Chairman.

THE CHAIRMAN: 781.2.

---EXHIBIT NO. 781.2: Interrogatory No. B14.9.17.

MR. B. CAMPBELL: Q. Doing these calculations in the way we have just gone through, Mr. Marcus, you would agree that the effect of using your figures on scenario A, table 2, page 13 of Exhibit 739, would be to lower the reserve calculation from 24 to 23.6 per cent?

MR. MARCUS: A. Under the assumptions which you have provided, that's correct, Mr. Campbell.

Q. Thank you. Finally, Mr. Marcus, I want to ask you, you have spoken about a number of other matters that relate to reliability, including lead times, you have had a conversation with my friend Mr. Hamer about approvals.

Is it fair to say that from a practical viewpoint all of these kinds of considerations do end up at the end of the day affecting the amount of reserve that is actually available as the years go by and what was the planning reserve margin becomes reality?

A. I would say that all of those factors plus a number of others, such as how well your load

forecast is doing, in fact do that.

Q. Sure. And looked at from that perspective, is it also fair to say that reliability is enhanced if a utility obtains approvals in a timely way so as to reduce the probability of deviation from planned in-service dates, regulatory approval is yet another factor that has to be considered in this?

A. I would say in most cases regulatory approval is not a significant factor, because Ontario Hydro has looked at specifically in these delays in on-line dates at what it projects four years from the on-line date.

So, unless you are having a regulatory approval that hasn't been gotten until four years before, in which case unless it's a combustion turbine unit, you are almost certain to be delayed, but it's not going to affect -- it's not going to significantly affect the reserve margin calculation since that has been based by Ontario Hydro in Exhibit 87 on knowledge of what was there four years in advance. So I would tend to say that regulatory approvals are not a big factor, although I can think of a few cases in which they would be.

Q. I am asking you to step back a little bit from the details of any year of the particular

calculations because I don't know of any of them that model regulatory delay in any explicit way. In-service delays can arrive for a variety of reasons and you have pointed to the four year figure that's used in the particular modelling.

I am saying when we are really talking about what realiability is intended to achieve, and not just the mathematics of it, that obtaining appropriate approvals or approvals for sufficient capacity to give you some flexibility in your implementation can be an important way of addressing long-term reliability issues, apart from any modelling.

[2:35 p.m.]

A. I would suggest that that is not necessarily true. I think we are going to talk about this issue some more in some of our evidence on later panels. But I think that from the point of view of enhancing reliability, basically knowing what you are dong four years in advance and perhaps having a few potential emergency approvals for CTUs on the shelf is what's important.

You may have some effects on energy costs on the other side of the equation versus effects of getting started and committed to things too early, so I don't think it's that important in reliability, even

stepping back from the question, except possibly for some emergency CTU approvals that could be drawn upon under certain very stringent specified conditions. I think it might have some effects on energy cost and they might go in both directions.

Q. And do you view the risks associated with the obtaining of project or regulatory approvals as symmetrical; that is, they are as likely to be obtained earlier than expected as later than expected?

A. I don't have any strong opinion. I think the evidence has suggested that it's in many cases approvals are later than planned. For example, I'm watching the Manitoba environmental assessment of Conawapa these days on behalf of another client; it's certainly getting bogged down.

But I think that unless it starts impinging upon the four-year period, it's not going to affect whether the lights are on in Ontario; it may affect the energy costs in Ontario and I'm not denigrating that. But from the point of view of my testimony on Exhibit 739 I don't think it affects it.

MR. B. CAMPBELL: All right, thank you.

Thank you, Mr. Chairman.

THE CHAIRMAN: Before I ask Mr. Shepherd if he has any reply questions, is there anyone who

wants to ask a question of the members of this panel?

Do you have any reply questions?

MR. SHEPHERD: Yes.

THE CHAIRMAN: Oh, sorry.

EXAMINATION BY DR. CONNELL:

Q. Mr. Marcus, in your simulation work, I presume you did not include any modelling of outages related to inter-area transmission?

MR. MARCUS: A. No, we didn't because those are not items which generation reserve margins tend to deal with, that's correct.

Q. From your knowledge do you think that there would be any significant difference amongst the models that you examined with respect to the impact of inter-area transmission outages?

A. I have seen certain people, certain utilities put in small numbers for inter-area transmission; I think that might actually be slightly more accurate and would raise the reserve margin slightly. It's only because inter-area transmission -- excuse me. Let me step back, Dr. Connell, I am confusing your question.

Inter-area transmission would be very hard to put into a generation reliability model. I was thinking of an inter-tie to something like the Manitoba

Purchase or as we have in California an inter-tie to the Northwest.

I have seen generation reliability modellers put small forced outage rates on those types of transmission lines and I think that would probably be generally appropriate. But I think that with respect to inter-area transmission within Ontario, it's a significant consideration but it is one for the transmission planners rather than the reliability modellers.

Q. But you don't think that the pattern of distribution of NUGs amongst areas would be a terribly important variable then with respect to reliability?

A. I think it's something that probably wouldn't be very important with respect to reliability. I think that the transmission planners tend in many cases to put in second contingencies and these types of things, so there will be transmission outages but with NUGs as well as with utility supply projects.

Utilities have typically not put those into their reserve margin unless it's something like a purchase from outside the utility that comes in over a particular type of radial line into the system. So, I think I would follow past practice on that and, you

know, recognize that transmission planners are going to have to do that planning and there may be some costs out there, whatever resources are put in, whether they're NUGs, whether they're utility resources and so forth. But I think it's a transmission planning matter.

Q. Thank you.

And, Mr. Kinosian, with respect to the proposal that DRA made with respect to SCE rates, that is, absorbing the cost of failing to meet their own forecast, does that in fact effectively replicate the circumstances that the NUGs in the same region would face?

MR. KINOSIAN: A. Yes, in California once the NUG signs its contract, its pricing is essentially fixed by what is said in that contract. So if it has cost overruns or poor performance, the NUG developer is at risk for those rather than ratepayers. So a proposal on SONGS 1 would have essentially put Edison and NUGs on an equal footing in that regard.

Q. In fact, do you know whether there are any NUGs that have encountered difficulties in meeting the terms of their contract; and, if so, have they ever appealed for a revision of those terms?

A. Yes, a number of NUG developers have

had problems. Some have resulted in the projects never being fully developed in the first place; others have gone out of business.

A few have come to the utilities requesting renegotiation of the contracts; and in a few of those instances, those have been brought to the Commission for approval, primarily NUGs that signed contracts many years ago before the Commission had set in place most of its policies on NUG contracts. And in those cases, which were referred to as pioneering NUGs, the Commission allowed the utility to renegotiate the contracts to assist the NUG projects in continuing operation. But that was a very limited circumstance with a few very early projects.

Q. Do you think it will ever happen again?

A. In more recent cases the Commission has required that the utility demonstrate that the renegotiated contract is in the ratepayers' best interest; that there be essentially a financial benefit to the ratepayers from whatever modification was made to the contract. So where there may be modifications to the contract to assist the NUG, while that might continue in the future, it will only be if ratepayers are getting a commensurate benefit out of the

modification also.

DR. CONNELL: Thank you.

THE CHAIRMAN: Anyone else before I call on Mr. Shepherd. (No response)

Mr. Shepherd.

MR. SHEPHERD: Mr. Chairman, I'll be brief.

RE-DIRECT EXAMINATION BY MR. SHEPHERD:

Q. Mr. Kinosian, Mr. Watson asked Mr. Marcus about his Footnote 6 which refers to a report by staff of the CPUC. Can you describe the difference between Commission staff and DRA and the Commission itself, just briefly?

MR. KINOSIAN. A. There are various parts of the Commission staff. One segment is DRA; there is another part of the commission staff, the compliance division; and there is a legal division; and a strategic planning division. So I believe overall there are four different divisions of Commission staff.

DRA is the only one which is essentially independent from the Commission in the views it takes and the actions it takes. The other three work for the Commission and respond to whatever the Commission wishes them to do on particular issues and proceedings.

Q. Mr. Marcus, Mr. Watson was asking you

what would happen to your delay numbers if you excluded the Darlington delays. Is it appropriate to exclude the Darlington delays?

A. I don't think it is. I think it's appropriate to look at all of the data you have. One of the great difficulties we have in analysis is the question of whether events are isolated or whether events are recurring.

And while specific events are isolated perhaps, one has to look at a number of other issues such as whether there are general patterns that have been recurring over time, so I would not exclude the Darlington situation. While it is somewhat extreme, I wouldn't exclude it as being so extreme that it should be counted as being equal to the average of everything else because it's a symptom of the complexity we face.

Q. Okay.

Mr. Kinosian, there was some discussion about the SONGS 1 facility being a demonstration facility. For the purposes of the analysis that you did and the analysis DRA did, was it treated as a demonstration facility or a commercial facility?

A. Both Edison and DRA in their analyses in the proceeding treated the plant as a normal commercial facility. The fact that it had originally

been considered a demonstration facility didn't enter into the analyses or the proceeding in any way.

Q. Mr. Hamer asked you questions, Mr. Kinosian, about whether SONGS 1 has unique problems. I guess my preliminary question is: Does SONGS 1 have more unique problems than other facilities, other nuclear facilities do? Is it somehow different in kind from other nuclear facilities?

A. Well, as I say on page 16 of my testimony here, there are a number of issues which need to be addressed in a review of nuclear facilities; some of which are likely to be specific to the individual plant.

The two issues mentioned regarding SONGS 1 are particularly unique to the plant, at least the steam generator tube sleeving is definitely unique to SONGS 1 in the magnitude of the sleeving that was performed.

Seismic problems will likely affect a number of other nuclear facilities.

And I would imagine other facilities would have their own unique problems, although I'm not an expert on all the other nuclear facilities so I can't say definitively whether they are all likely to have the same number or a higher or lower number of

unique problems than SONGS 1 had.

Q. Okay. And that I guess leads to the more general question. You were asked quite a number of questions about whether a particular problem of SONGS 1 applies to CANDU, et cetera. Is the intent of your evidence to suggest that you should just take your sort of SONGS 1 analysis and plug in the Bruce numbers and come up with a decision for Bruce?

A. No, not at all. What I am suggesting is that a detailed critique, review of the CANDU facilities should be performed if there is a situation wherein there is a significant capital cost to be performed or if performance is degrading at the facilities, so that a question of its cost-effectiveness might be raised.

And I'm not suggesting that any of the specific problems raised with SONGS 1 necessarily will apply to any of the CANDU facilities.

MR. SHEPHERD: Mr. Chairman, I expect to be five minutes if that's okay to proceed.

THE CHAIRMAN: Fine.

MR. SHEPHERD: Q. You were asked by Mr. Hamer whether you, whether and why you excluded nuclear environmental impacts, externalities in effect, in your report. And you said you did exclude them. Why?

MR. KINOSIAN. A. We did not have the time or the staffing or the expertise to do a detailed analysis of all the potential environmental impacts of nuclear plants. Our Commission has gone to, has spent a lot of time to develop a methodology which it's constantly revising for evaluating air emissions.

Given the amount of staffing and time we had to do a review of SONGS 1, there was no way our staff could do a comparable indepth detailed proposal for evaluating all the environment impacts of nuclear plants.

We did mention in our report that impacts other than environmental considerations exist and we cited a study done by Pace University regarding the different environmental impacts of various resources, though we did not include those values in our analyses because as I have indicated we really did not have the time or the expertise to develop or support specific numbers for SONGS.

Q. If your analysis had not shown a $500-million disbenefit to keeping it open, would that have changed your approach to nuclear externalities or your decision on whether to deal with them?

A. Given the conditions we faced, I don't think there is any way we could have done

anything differently regarding the nuclear environmental considerations.

Q. I just have to check my notes to see who was asked this question. Mr. Hamer asked you, Mr. Marcus, about gas transmission outages being common mode type failures. Are you familiar with how many gas pipelines routes there are from Western Canada or from gas sources to Ontario?

MR. MARCUS: A. There are a number of routes. From Western Canada there is one main pipeline but it has quite a bit of redundancy and looping on it.
[3:04 p.m.]

And in addition there are pipelines that come into the Union Gas service territory which connect with the ANR Pipeline in Michigan and then further connect down into all of the gas supply sources in the southern United States. So that Ontario does have a significant amount of gas pipeline capability from several different supply regions coming in.

Q. Mr. Kinosian, Mr. Hamer gave you a hypothetical of building a nuclear station to displace emissions from fossil facilities in California. Under the current regulatory regime would it be possible for a utility to build a 3,000 megawatt nuclear facility in California?

MR. KINOSIAN: A. No, under current California law it would not be possible to build any nuclear facility in California until such time as nuclear waste disposal problems have been resolved.

MR. SHEPHERD: Those are all my questions, Mr. Chairman.

---Panel withdraws.

THE CHAIRMAN: Thank you.

We will now be adjourning in a moment or two until tomorrow morning at nine o'clock.

The CEG is next. That is Mr. Starkman; right?

MR. STARKMAN: Yes.

THE CHAIRMAN: And then Northwatch is next. When do you expect to be on, Mr. Greenspoon?

MR. GREENSPOON: I expect at 9:00 a.m. on Thursday morning.

THE CHAIRMAN: On Wednesday morning.

MR. GREENSPOON: Wednesday morning.

THE CHAIRMAN: And then MEA. When do you expect to be on, Mr. Watson?

MR. R. WATSON: My understanding is 9:00 a.m. Thursday morning.

THE CHAIRMAN: Do you all think that you will be through by three o'clock in the afternoon?

That is the general plan; is that correct?

MR. R. WATSON: I am certainly counting on that.

MR. GREENSPOON: Yes, sir.

MR. STARKMAN: Yes.

MR. R. WATSON: I think you might be better advised to ask some of my colleagues.

THE CHAIRMAN: I understand that. I understand that.

I take it there is nobody else that plans to bring evidence in Panel 1; is that correct? No one else here in any event; is that correct?

We will adjourn until tomorrow morning at nine o'clock. Thank you very much.

THE REGISTRAR: Please come to order. This hearing will adjourn until nine o'clock tomorrow morning.

---Whereupon the hearing was adjourned at 3:07 p.m., to be reconvened on Tuesday, October 27, 1992, at 9:00 a.m.

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